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ERCB REPORT 75-L

THE SENSITIVITY OF CRUDE OIL RECOVERY TO PRODUCTION RATE AND THE NEED FOR SURVEILLANCE OF THE EFFECT OF PRODUCTION RATE ON RECOVERY AND FOR REGULATION OF PRODUCTION RATE

SEPTEMBER 1975

1 Alberta

ENERGY RESOURCES CONSERVATION BOARD
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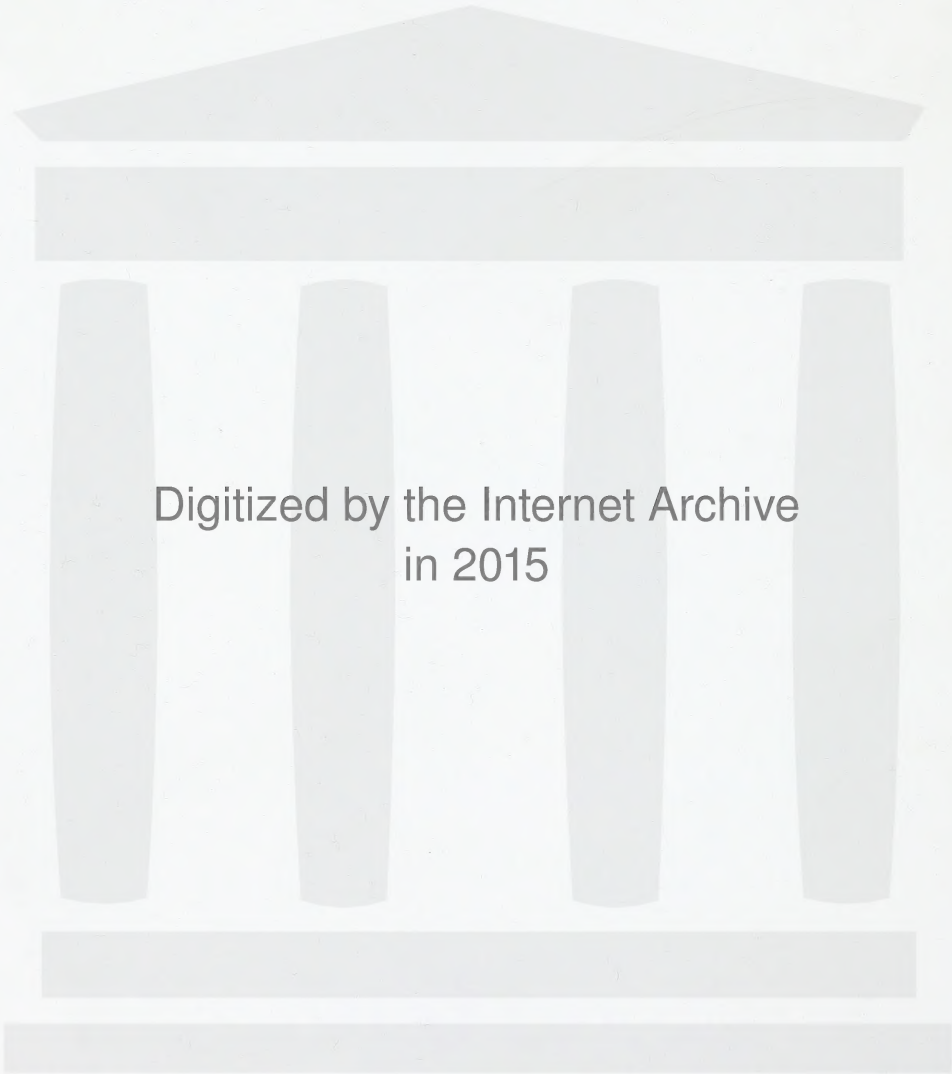

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Price: $5.00

ACKNOWLEDGEMENT

This report, like others produced by the Board, is the result of detailed work by many of the Board's staff. R. A. Purvis, P. Eng., N. A. Strom, P. Eng., and H. R. Keushnig, P. Eng. carried the major staff responsibility. The Board also acknowledges the assistance of Dr. N. Mungan and Dr. N. R. Morrow of the Petroleum Recovery Institute in checking certain of the material in section 6 of the report.

PREFACE

Evaluation of the practical effect of production rate on crude oil recovery requires the simultaneous consideration of several individual factors. These factors may be broadly grouped under the classifications of (a) physical properties of reservoir rocks and fluids, (b) reservoir oil recovery processes, and (c) development and operating practices. While the effects of some factors are direct and easily assessed, others are strongly interdependent and their specific effect is difficult to assess. The effects of individual factors have been considered separately for convenience, but their interrelationships should always be kept in mind.

Evaluation of the effect of production rate on oil recovery tests the limits of present reservoir engineering knowledge. Accordingly, in this report the analysis of each of the basic factors is presented in two parts, a summary of the widely accepted knowledge, followed by individual views which in many instances are new, unproved or contentious. The Board has made its best judgement having regard both for the widely accepted knowledge and the views expressed by individuals. It is hoped that the report will stimulate further investigation into areas where there are gaps in basic knowledge.

SUMMARY

The Oil and Gas Conservation Act gives the Energy Resources Conservation Board the general responsibility of effecting the conservation and preventing the waste of crude oil in Alberta. One of the possible causes of waste of recoverable crude oil in the reservoir is a high rate of production, either from individual wells or from the reservoir as a whole.

The Background

The Board considered the need for maximum rate limitations (MRLs) and the sensitivity of recovery to production rate in 1965 when it held a special hearing and issued a subsequent report, OGCB 65-3. It concluded that the sensitivity of recovery to production rate varied depending largely on the reservoir recovery process - recovery from expansion drive above the bubble point was believed to be the least sensitive to production rate while displacement by miscible fluids was believed to be the most sensitive. The Board concluded that both individual-well rate and overall-pool rate could be important to ultimate recovery. The Board adopted a simple preliminary rate limitation (PRL) formula based on pool recoverable reserve and cumulative production as a means of surveillance to identify pools where production rates were of concern. The PRL was also used as a basis for interim control until further studies were performed.

The increased market demand in the early 1970's resulted in greatly increased production rates in many pools. By early 1973 the prorated allowables of many pools had reached or exceeded levels suggested by the PRL formula. As a result the Board imposed MRLs (based primarily on the PRL formula) on a number of pools or portions of pools effective November 1, 1973. At the same time the Board announced that another hearing to consider MRLs would be held in March 1974.

The limits specified by the PRL formula have been applied to heavy-gravity crude oil pools since 1965. This was necessary because heavy-gravity crude oil is not subject to proration and because detailed rate studies were not submitted for individual pools.

The 1974 Hearing

The formal notice of hearing was issued on December 28, 1973 stating the purpose to consider methods for determining MRLs and the need or otherwise for continuing the existing Proration Plan. A submission by the Board staff was filed on January 31, 1974 and submissions by others were required to be filed by February 28, 1974. A total of 19 primary submissions were received. Responses to the submissions were required before March 14, 1974 and a total of 20 were received, of which 9 were from participants who had filed primary submissions. The hearing was in session for 5 days commencing on March 27, 1974 and closed on April 9, 1974.

The Board staff submission assumed that ultimate recovery is sensitive to production rate and that there is a general need to regulate individual well production rates. The Board staff proposed a new empirical PRL formula where the initial PRL would be based on oil mobility and the initial oil in place. It proposed a general method for administering MRLs where individual wells would initially be permitted to produce more than their DSU allocation, but this flexibility would be systematically decreased with cumulative production to encourage operation of all capable wells in the latter stages of depletion. The administrative aspects were designed to be compatible with the Proration Plan. The Board staff proposed that PRLs specified by its system be applied in those cases where suitable MER or rate-recovery sensitivity studies were not available or found to be unreliable compared to actual pool performance.

An analysis by the Canadian Petroleum Association of selected pools representing over 60 per cent of the Province's remaining reserves led to the conclusion that implementation of the Board staff proposal would curtail production from these pools by some 30 per cent under conditions prevailing at the end of 1973.

Submissions by the industry participants almost unanimously recommended rejection of the Board staff proposal. Most of the participants questioned the validity of the proposal or any other proposal based on a single generalized formula. Most disagreed with the concept that rate limitation would lead to improved recovery, but many acknowledged that

some form of PRL or MRL formula could be used as a surveillance device to identify situations warranting attention.

Many participants contended that adverse sensitivity of recovery to production rate in practical terms may be expected only in certain situations which represent a relatively small portion of the total. They stated that the application of individual controls, perhaps only where recovery losses were shown to be occurring, would be more reasonable than a highly structured administrative procedure applied to all pools except those on good production practice. Some participants contended that the Board's current voidage replacement, and other requirements in enhanced recovery approvals, were sufficient to prevent reservoir waste. Most industry participants agreed that any rate restrictions should be based on individual-pool studies.

Ashland, Great Plains, Home, and Imperial presented the results of reservoir simulation studies of certain water-flood recovery processes. These studies indicated that while higher production rates usually resulted in earlier coning or water breakthrough, final oil recovery was not reduced and could in fact be increased. This was attributed to better flushing of the reservoir since more water could be produced before reaching the economic limit.

Regarding limitations on individual-well rate as opposed to pool rate, several operators contended that a wide range of individual-well rates was required to achieve maximum recovery. Others recommended that individual-well rates in certain situations should be restricted on the basis of pressure draw-down or other appropriate factors. Some participants contended that GOR and WOR penalties and voidage replacement requirements provided sufficient control of individual well rates, but there was no consensus on the base rate to which penalties would be applied. Imperial contended that high individual-well rates could lead to a loss of ultimate recovery only where, if a well became uneconomic to operate, it was uneconomic to replace it, and the oil could not be produced from other wells.

A number of submissions emphasized the effect that any MRL could have on the economic incentive for continued exploration and development, particularly with respect to heavy-gravity crude oil pools. Several participants recommended that no MRLs be applied to these pools.

The Decision

The Board has drawn from the evidence at the hearing, the technical literature, the knowledge of its staff, and its own knowledge to review the possible effect on oil recovery and the sensitivity of oil recovery to production rate, of each of:

(a) reservoir rock properties,

(b) reservoir fluid properties,

(c) reservoir rock-fluid interactions,

(d) oil recovery processes, and

(e) development and operating practices.

With respect to reservoir rock properties, the Board agrees with most participants that increased rock heterogeneity tends to impair volumetric displacement efficiency and therefore reduce ultimate oil recovery. It accepts that certain types of heterogeneity may not be detrimental to recovery by water-flood provided operations are continued to the economic limit, but the Board is not prepared to extrapolate this conclusion to the random type of heterogeneity of some reservoirs. Because of the wide variations in the level of porosity and permeability encountered in some reservoirs and the difficulty of adequately accounting for them even in sophisticated reservoir analyses, the Board does not accept that the full effects of variation in reservoir rock properties on recovery and on the sensitivity of recovery to production rate can be fully evaluated. Accordingly, for reservoirs showing significant heterogeneity the Board believes it appropriate to assume that increasing production rate could decrease oil recovery and that it should exercise caution in authorizing production rates above those generally accepted as safe.

The Board agrees with most of the participants that, with the exception of oil viscosity, reservoir fluid properties themselves do not have much effect on either the level of oil recovery or the sensitivity of recovery to production rate. It agrees with several of the participants that increased oil viscosity has an unfavourable effect on areal and vertical sweep efficiencies and on the rate of water imbibition. These adverse effects of high oil viscosity lead to low oil recovery and in the Board's view increase the probability that high production rates could adversely affect oil recovery.

Notwithstanding the extensive amount of research which has been done on the subject of reservoir rock-fluid interactions the Board finds serious gaps in the understanding of the effects of wettability, capillary behaviour and relative permeability on the level of oil recovery and the sensitivity of recovery to production rate. Where uncertainty of rock-fluid interactions could have a significant effect on the recovery process, the Board believes that caution should be exercised in setting production rates until these interactions are more clearly understood (e.g. their in situ values determined and their potential effects assessed).

Dealing with the various oil recovery processes the Board believes that there is potential for rate sensitivity under certain conditions in all types of drive mechanisms, except perhaps in the case of simple expansion drive. Recovery will be reduced in any situation where changes to well or pool rates cause a less efficient drive to supplant a more efficient one (e.g. solution gas drive replacing a water drive) in any portion of a reservoir. Crude oil recovery may also be reduced where increased rates result in increased gas or water production because of coning.

The Board believes there is little risk of reduced recovery due to high production rate in homogeneous or randomly heterogeneous reservoirs with favourable rock and fluid properties (principally high permeability and low oil viscosity) with normal pool development and operating practices. The potential for adverse rate sensitivity is believed to increase as stratification increases and as rock and fluid properties become less favourable. In pools having high stratification and unfavourable rock and fluid properties, oil recovery is normally quite sensitive to production rate and economic constraints. The Board recognizes, however, that stratification can have a beneficial effect by inhibiting coning under some circumstances.

In reaching these conclusions, the Board to some degree questions the ability of numerical simulation methods to correctly represent the recovery processes in some reservoirs. The Board, however, accepts that high production rates in fully pressure maintained water-floods will increase ultimate recovery provided that it is economical and practical to cycle large volumes of water.

The aspects of development and operating practices which are believed to have an important effect on recovery or its sensitivity to production rate are the capacity and flexibility of installed facilities. This implies advantages to close spacing, large casing, and a high degree of flexibility in production and injection facilities, so that any irregular reservoir performance may be counteracted. Also appropriate scheduling of injection into and production from major zones in stratified reservoirs may be required to increase any beneficial effect or decrease any adverse effect of production rate on recovery.

On the basic question of the need for surveillance of the effect of production rate on reservoir performance and oil recovery, the Board believes that surveillance of both individual wells and pools is necessary for several purposes. It serves to identify cases where the sensitivity of ultimate recovery to production rate should be investigated. Surveillance is also necessary to ensure that an agreed-upon depletion plan is being followed and to assess production performance relative to that predicted for the depletion plan. Finally, surveillance is required to identify cases of unusual or adverse performance, which if permitted to continue, would reduce ultimate recovery.

The Board believes that several methods should be used to identify cases where rate sensitivity should be investigated. These may include all of the methods suggested at the hearing including those based on reserve or life index, rock and fluid properties, and production parameters. The need and urgency for detailed investigation in any particular case would be expected to increase as more surveillance tests indicate the need.

Detailed reservoir studies would continue to be carried out by the individual operators to outline the pool depletion plans and investigate enhanced recovery alternatives. The requirements for rate sensitivity studies may vary considerably among individual cases and there should be some prior mutual agreement between the operator and the Board staff on their scope. In some cases, a reservoir study may simply be extended to include a rate sensitivity analysis.

The Board concludes that the monitoring and analysis of production performance on a continuing basis should also be primarily the responsibility of the individual operator. This should be essentially in the form

of the progress reports which are submitted periodically for all enhanced recovery schemes. An explicit documentation of completion intervals, oil, gas and water production rates and ratios, voidage replacement, pressures, interface levels, displacement profiles both vertical and horizontal, and operating conditions and problems will be required on both an individual well and pool (or project) basis where appropriate. Analysis of the trends of these production parameters and comparison to predictions for the depletion plan will also be required.

Implementation

The Board expects that it will take several months to fully implement its general conclusion that surveillance procedures should be broadened and strengthened and that the actual application of pool and individual-well MRLs should be more selective. The Board will, however, remove MRLs on January 1, 1976 from those pools where it appears that high production rates are not likely to affect ultimate recovery. It expects that appropriate pool or individual-well MRLs will be determined and implemented on May 1, 1976 in those cases where they are judged or proven to be necessary. The exact timing and administrative details of these changes will be announced by informational letters.

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1 INTRODUCTION

The Board called a public hearing in March 1974 to consider matters related to maximum rate limitations (MRLs) and the system of crude-oil prorating in the province of Alberta. In this report the Board examines the representations made at the hearing, and, based on these and its own knowledge, records its decision respecting matters relating to MRLs.

1.1 Background

An overriding provision of the present proration plan* has been that allowables based upon market demand would be subject to rate limitations if and when necessary in the interests of conservation. The present plan for maximum rate limitations was outlined in the Board's publication, OGCB 65-3.** The bases of the MRL plan are rate limits determined by engineering studies or a preliminary rate limitation formula, acreage distribution of MRLs to pool production entities, and a production accounting procedure. The plan has been used to determine MRLs for heavy-gravity oil pools since 1965.

During the period from late 1950 to 1971 the market demand for oil from the light- and medium-gravity oil pools was substantially below their productive capacity. Thus, MRLs were not required on a general basis since production rates were restricted because of prorating, and there was no need for further restriction of rates to prevent waste and ensure conservation. By 1970 and early 1971 the market demand for conventional crude oil had increased to levels where the Board believed it necessary to reconsider the need for MRLs for light- and medium-gravity oil pools. It issued an Informational Letter on March 9, 1971 (IL 71-5, reproduced in Appendix A), alerting operators that it was considering

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* Report and Decision on Review of Plan for Proration of Oil to Market Demand in Alberta. July 1964. OGCB 64-10.

** Report and Decision on Review of Plan for Maximum Oil Production Rate Limitation in Alberta. March 1965. OGCB 65-3.

the introduction of acreage equivalent MRLs in these pools by July 1971. Subsequently, the Board reviewed the matter and issued another Informational Letter on August 11, 1971 (IL 71-22, reproduced in Appendix B), stating it would defer action at that time.

By early 1973 the prorated allowables of many pools had exceeded the level of their preliminary rate limitations (PRLs), and in some instances the application of pool incapability factors had increased pool allowables so that the application of penalty factors was no longer an effective method of controlling excessive gas and water production. On July 30, 1973, the Board issued an Informational Letter (IL-OG 73-24, reproduced in Appendix C) proposing that "good production practice" (GPP) status be extended to some additional pools, that MRLs be imposed on the majority of light- and medium-gravity pools, and that a public hearing be called toward the end of March 1974 to reconsider methods of establishing MRLs. The letter included a tabulation of tentative MRLs proposed by the Board and called for submissions by October 1, 1973, respecting these. Company submissions were reviewed and, effective November 1, 1973, the Board imposed MRLs on certain pools or portions of pools where rate limitation was judged necessary in the interest of conservation.

1.2 The Hearing

The notice of hearing (reproduced in Appendix D) was issued on December 28, 1974, and stated that Proceeding No. 7511 would commence, on March 27, 1974, to consider methods for determining MRLs and the need or otherwise for continuing the existing Proration Plan. The notice stated that the Board staff would file, on January 31, 1974, a submission concerning proposed methods for the determination and administration of MRLs. It provided for the filing of submissions by interested persons on or before February 28, 1974, and of responses to submissions on or before March 14, 1974.

While the notice of hearing indicated that the methods for determining MRLs would be the principal issue, the Board also received submissions dealing with the more basic questions of the sensitivity of oil recovery

to production rate and the need for MRLs. The Board accepted and has considered all submissions made to it.

The hearing was held in the Court House, Calgary, Alberta, with G. W. Govier, P. Eng., D. R. Craig, P. Eng., and V. Millard sitting. The Board sat for five days and the hearing closed on April 9, 1974.

1.3 Appearances

Table 1-1 lists participants at the hearing and, where applicable, their representatives.

The submission by Ashland Oil Canada Limited (Ashland)* included an engineering study by Neotechnology Consultants Limited (Neotec)* entitled, "Effect of Rate on Recovery from Horizontal Water Floods".

Ashland filed a primary submission which was supported by the following operators and working interest owners in the Pembina Keystone area:

Ashland Oil Canada Limited
Baldonnel Oil and Gas Ltd.
BP Exploration Canada Limited
Canada-Cities Service, Ltd.
Canadian Industrial Gas & Oil Ltd.
Canadian Reserve Oil and Gas Ltd.
Canadian Superior Oil Ltd.
Denison Mines Limited
J. M. Huber Corporation
Hudson's Bay Oil and Gas Company Limited
Husky Oil Operations Ltd.
Kerr-McGee Corporation
PanCanadian Petroleum Limited
Rulair Oil Ltd.
Scurry-Rainbow Oil Limited
Texaco Exploration Canada Ltd.
Tricentrol Canada Limited
Westburne Petroleum & Minerals Ltd.
Western Decalta Petroleum Limited

The submissions of Great Plains Development Company of Canada, Ltd. and Shell Canada Limited included an engineering study conducted by Intercomp Resource Development and Engineering Ltd. (Intercomp)*

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*Abbreviation used throughout report.

entitled, "A Study of the Sensitivity of Oil Recovery to Production Rate". The Intercomp study was also supported by the following petroleum companies:

Alminex Limited
Aquitaine Company of Canada Ltd.
Home Oil Company Limited
Hudson's Bay Oil and Gas Company Limited
PanCanadian Petroleum Limited
Texaco Exploration Canada Ltd.

TABLE 1-1

APPEARANCES

Note: Abbreviation of name shown in parentheses is used throughout report.

	Representatives	Witnesses
Alminex Limited (Alminex)		
	R. A. Beamish, P. Eng.	R. A. Beamish, P. Eng.
Ashland Oil Canada Limited (Ashland) (PP)		
	F. E. Starratt, P. Eng.	D. H. Stright K. Aziz, P. Eng. (of Neotec) D. W. Bennion, P. Eng. (of Neotec)
Canus Petroleum Limited (Canus)		
	V. O. C. Wilson, P. Eng.	V. O. C. Wilson, P. Eng.
D&S Petroleum Consultants Ltd. (D&S)		
	W. G. Fisher, P. Eng.	W. G. Fisher, P. Eng. R. M. Borden (of Bumper Development Corporation Ltd.) G. L. Hayes, P. Geol. (of Bumper Development Corporation Ltd.) A. B. MacDonald (of Andex Oil Co. Ltd.)
Dome Petroleum Limited (Dome)		
	J. L. D. Cooper, P. Eng.	J. L. D. Cooper, P. Eng.
Great Plains Development Company of Canada, Ltd. (Great Plains)		
	F. T. Nadir, P. Eng. T. W. Adamson, P. Eng.	F. T. Nadir, P. Eng. T. W. Adamson, P. Eng. K. H. Coats (of Intercomp) S. B. Beveridge, P. Eng. (of Intercomp)

	Representatives	Witnesses
Gulf Oil Canada Limited (Gulf)		
	T. E. Randall, P. Eng.	T. E. Randall, P. Eng.
Home Oil Company Limited (Home)		
	A. G. Morison, P. Eng. J. R. Sears, P. Eng.	A. G. Morison, P. Eng. J. R. Sears, P. Eng.
Hudson's Bay Oil and Gas Company Limited (Hudson's Bay)		
	S. A. Morgan, P. Eng. S. K. Chakravorty, P. Eng.	S. A. Morgan, P. Eng. S. K. Chakravorty, P. Eng.
Husky Oil Operations Ltd. (Husky)		
	W. Abel, P. Eng. M. Chorney, P. Eng. R. G. Pitt, P. Eng.	R. G. Pitt, P. Eng.
Imperial Oil Limited (Imperial)		
	R. G. Niven, P. Eng.	R. G. Niven, P. Eng. J. E. Lee, P. Eng. J. G. Richardson (of Esso Production Research Co.)
Independent Petroleum Association of Canada (IPAC)		
	C. S. Dunkley, P. Eng.	C. S. Dunkley, P. Eng.
Mobil Oil Canada, Ltd. (Mobil) (PP)		
	H. G. Groeneveld, P. Eng.	H. G. Groeneveld, P. Eng. C. L. McMichael (of Mobil Research and Development Corp.)
Petrofina Canada Ltd. (Petrofina)		
	A. Jain, P. Eng.	A. Jain, P. Eng.
Shell Canada Limited (Shell)		
	J. W. Serra, P. Eng. R. G. Gorrill, P. Eng.	J. W. Serra, P. Eng. R. K. Agrawal, P. Eng. (of Intercomp) K. H. Coats (of Intercomp) S. B. Beveridge, P. Eng. (of Intercomp)

	Representatives	Witnesses
Texaco Canada Limited (Texaco Canada)		
	J. G. Pashniak, P. Eng.	J. G. Pashniak, P. Eng.
Texaco Exploration Canada Ltd. (Texaco Exploration)		
	M. N. Young, P. Eng.	M. N. Young, P. Eng.
	D. P. O'Neill	D. P. O'Neill
Union Oil Company of Canada Limited (Union)		
	D. S. Paxman, P. Eng	D. S. Paxman, P. Eng.
	J. W. Wasson, P. Eng.	J. W. Wasson, P. Eng.
	J. T. Duree, P. Eng.	J. T. Duree, P. Eng.
Energy Resources Conservation Board staff (Board staff)		
	N. A. Strom, P. Eng.	N. A. Strom, P. Eng.
	R. A. Purvis, P. Eng.	R. A. Purvis, P. Eng.

The following did not submit primary submissions but appeared for the purpose of supporting the responses filed, or for the purpose of cross-examination or argument:

	Representatives	Witnesses
Amerada Minerals Corporation of Canada Ltd. (Amerada)		
	L. J. Crandal	L. J. Crandal
Amoco Canada Petroleum Company Ltd. (Amoco)		
	J. D. Griffith, P. Eng.	J. D. Griffith, P. Eng.
		H. Simons, C.E.T.
Aquitaine Company of Canada Ltd. (Aquitaine)		
	A. D. Bradshaw, P. Eng.	A. D. Bradshaw, P. Eng.
	R. D. Waymouth, P. Eng.	R. D. Waymouth, P. Eng.
Atlantic Richfield Canada Ltd. (Atlantic Richfield)		
	M. N. Kinakin, P. Eng.	M. N. Kinakin, P. Eng.
BP Exploration Canada Limited (BP)		
	R. G. Kessler, P. Eng.	R. G. Kessler, P. Eng.

	Representatives	Witnesses
Canadian Petroleum Association (CPA)		
	H. Maceij	H. Maceij S. K. Chakravorty, P. Eng.
Chevron Standard Limited (Chevron)		
	L. J. Kolada, P. Eng. P. V. Malowany, P. Eng.	L. J. Kolada, P. Eng. G. A. Johnson, P. Eng.
Kerr-McGee Corporation (Kerr-McGee)		
	B. P. Stauss	B. P. Stauss
D. R. McCord and Associates (McCord)		
	W. S. Woods, P. Eng.	W. S. Woods, P. Eng.
PanCanadian Petroleum Limited (PanCanadian)		
	K. M. Carter, P. Eng. S. B. Beveridge, P. Eng.	K. M. Carter, P. Eng. S. B. Beveridge, P. Eng. (of Intercomp)
Wainoco Oil Ltd. (Wainoco)		
	D. A. Nikiforuk, P. Eng.	D. A. Nikiforuk, P. Eng.

1.4 Terminology

The following definitions apply to terms used in this report:

Block - an area or part of a pool consisting of production spacing units grouped for the purpose of obtaining a common, aggregate production allowable.

Control Well - a well capable of producing which is within a block or project and which is completed nearer than the least side dimension of its drilling spacing unit to a portion of the boundary of the block or project which is also a boundary of a drilling spacing unit containing a producing well outside the block or project.

Crude Oil - a mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or

is recoverable at a well from an underground reservoir and is liquid at the conditions under which its volume is measured or estimated, and that includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate. Crude oil normally will be deemed to be heavy-gravity crude oil if it has a gravity of 25 or numerically less, measured in degrees on the American Petroleum Institute scale, but the Board, in a particular case, may classify crude oil otherwise than in accordance with this criterion when appropriate having regard to its market utilization and purchasers' classification.

Drilling Spacing Unit (DSU) - the surface area associated with and prescribed for an oil well and

(a) the surface vertically beneath that area, or

(b) where the DSU is prescribed with respect to a specified pool, geological formation, member or zone, the pool, geological formation, member or zone vertically beneath the area.

Good Production Practice (GPP) - production of crude oil or raw gas at a rate

(i) not governed by a base allowable, but

(ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production.

This is a classification of pools used by the Board either to permit improvement of the economics of production and thus deferral of the date of abandonment of a pool, or to avoid unnecessary administrative expense associated with regulation of production rates where this serves little or no purpose.

Market Demand - the amount of oil or gas reasonably needed for current consumption, use, storage and working stocks within and outside Alberta.

Maximum Efficient Rate (MER) - the maximum rate at which oil can be produced without avoidable underground waste.

Maximum Permissible Rate (MPR) - the Board's engineering estimate of the individual-well maximum rate at which oil can be produced without causing economically avoidable underground waste.

Maximum Rate Limitation (MRL) - is the maximum rate of production prescribed for the avoidance of waste, after application of any applicable penalty factor.

Maximum Rate Unit (MRU) - a separable portion of a pool to which an MRL is assigned.

Minimum Allowance - the lowest allowable, before the application of any applicable penalty factors, that is assigned to a producing oil well, related to the average well-depth of the pool, and designed to allow return of oil well completion costs and direct operating costs and prevent premature abandonment.

Pool Incapability Factor (PIF) - a factor by which a pool's reserves allocation is adjusted upward to permit high-capacity wells in a pool to offset regulatory restriction or the lack of productivity causing reduced production from other wells in the pool.

Preliminary Rate Limitation (PRL) - a preliminary or initial estimate of the MRL applicable to a production entity.

Production Entity - a production spacing unit, block, project or pool.

Production Spacing Unit (PSU) - a spacing unit consisting of one or more adjoining drilling spacing units of common ownership.

Project - a pool or part thereof in which operations in accordance with a scheme for enhanced recovery of oil, approved by the Board, are conducted or, where the scheme provides for the application of more than one recovery mechanism, the part of the area subject to the scheme which is subject to one such recovery mechanism.

Target Area - the part of a drilling spacing unit within which a well for the purpose of producing oil or gas may be completed without reduction of its allowable because of its location.

2 LEGISLATIVE PROVISIONS REGARDING CONTROL OF PRODUCTION RATE OTHER THAN BY PRORATION

The Board regulates oil production rates in accordance with procedures developed by it over the years and enunciated in reports and Informational Letters referred to in Section 1 above. The powers exercised by the Board in so doing are granted to it by The Oil and Gas Conservation Act. Details of the rules followed are set out in the reports and Informational Letters and in the Oil and Gas Conservation Regulations established pursuant to The Oil and Gas Conservation Act.

2.1 The Oil and Gas Conservation Act

Section 5 of the Act states in part, "The purposes of this Act are

(a) to effect the conservation of, and to prevent the waste of, the oil, gas and crude bitumen resources of Alberta,

(b) to afford each owner the opportunity of obtaining his share of the production of oil or gas from any pool or of crude bitumen from any oil sands deposit."

The provisions of the Act most directly related to the regulation of production rate are contained in section 36, which reads in part as follows:

36. The Board may, by order,

(a) control and regulate the production of oil, gas and water by restriction, proration or prohibition.

The authority for the pertinent provisions of the Oil and Gas Conservation Regulations is found in section 22 of the Act, which reads in part as follows:

22. (1) The Board may make regulations

10. prescribing rules by which the base allowable of a well in a production spacing unit or of a block or project may be determined;

32. prescribing rules for the calculation of allowables, maximum production rates, penalty factors, penalties and overproduction or underproduction status;

44. generally to conserve oil and gas, and to prevent waste or improvident disposition thereof, and to do any other matter reasonably incidental to the development and drilling of any oil or gas wells, the operation thereof, and the production therefrom.

Some additional relevant powers are set out in section 33 as follows:

33. (1) The Board may, by order,

(a) designate a field by describing the surface area thereof, or

(b) designate a pool by describing the surface area vertically above the pool and by naming the geological formation, member or zone in which the pool occurs or by such other method of identification as the Board in any case considers suitable, or

(c) designate the area that is to be allocated to a well in connection with fixing allowable production.

2.2 The Oil and Gas Conservation Regulations

Details regarding the calculation and administration of allowables are outlined in Part 10 of the Oil and Gas Conservation Regulations. It provides that the licensee may take production only at rates in accordance with the subsisting MD order or other order of the Board governing rates of production.

Part 10 also provides for the application of appropriate penalties for excessive production of oil, or of gas or water in combination with oil. It also provides for the manner in which production may be taken from production spacing units (PSU), blocks and projects. It specifies that with regard to blocks and projects the production from or injection to any pool should be distributed in such a manner as to obtain the optimum recovery of oil or gas from the pool.

3 PRESENT METHOD OF SURVEILLANCE OF THE EFFECT OF PRODUCTION RATE ON RECOVERY AND OF REGULATION OF PRODUCTION RATE

The historical developments and decisions of the Board that have led to the present method and practice of surveillance of the effect of production rate on recovery and of regulation of production rate are reviewed in this section of the report.

3.1 Report OGCB 65-3

Report OGCB 65-3 was issued by the Board in March 1965 following a special hearing called to receive representations concerning methods of limiting maximum daily rates of production of crude oil and to consider some changes respecting gas-oil ratio (GOR) penalties. The principal issues considered were the sensitivity of pool recovery to pool and individual-well production rates for the various drive or recovery mechanisms, and the need for limitation of pool and individual-well production rates on either a daily or monthly basis.

While very little quantitative evidence was submitted at the hearing, the Board agreed with the general view of industry that the type of drive or recovery mechanism was the most important factor in the consideration of rate sensitivity. Recovery of oil through reservoir depletion by oil expansion above the bubble point pressure was considered insensitive to production rate. Other drive mechanisms were considered to be increasingly sensitive to production rate in the following order: solution gas drive, displacement by water, displacement by gas, and displacement by miscible fluids. The Board considered that for each drive or recovery mechanism the volume of reservoir swept would be somewhat dependent upon the production rate. The Board also agreed with the view of industry that MER studies should serve as the basis for determining MRLs. The difficulties of determining the MER, particularly during the early producing life of a pool, were discussed and Imperial made a specific proposal for estimating PRLs or interim MRLs in an attempt to solve this problem.

The Board concluded that pool recovery could be influenced by pool rates in excess of those permitting efficient oil displacement in the reservoir as a whole or by individual-well rates leading to dissipation of the reservoir energy or impaired local displacement. Pool MRLs would be affected by such factors as pool bottom-hole pressure levels and rate of advance of interfaces whereas well MRLs would be chiefly affected by gas and water coning. The Board stated that at any particular stage of depletion, the controlling MRL could be either the reservoir MRL or the summation of the individual well MRLs. It was recognized that well spacing would be a significant factor in those cases where the controlling MRL was the summation of individual-well MRLs.

The Board decided that daily MRLs were not generally necessary for pools or pool segments and that suitable monthly MRLs would be set as and when necessary for these entities. The Board did, however, make provision for application of individual-well daily or monthly MRLs where it considered that the ultimate oil recovery from the pool would otherwise be adversely affected. The Board emphasized that there should be no difference in principle in the application of MRLs to either light- and medium- or heavy-gravity crude oil pools.

The Board concluded that it was necessary in all cases to keep pool performance under careful surveillance. To provide a uniform basis for alerting itself and industry to the need for further study it adopted the Imperial maximum monthly rate formula in the following form:

$$PRL = K \times 10^{-6}(U - P/2)$$

where: PRL = preliminary rate limitation for a pool or separable portion, barrels per month,

K = a constant normally taken as 9,000, but values of 7,000 or 11,000 were to be used where the pool's characteristics and recovery mechanism were such as to suggest it,

U = the ultimate recoverable reserves in stock tank barrels,

P = the cumulative production in stock tank barrels.

This PRL formula was adopted to serve as a monitoring and interim control device to indicate those pools or parts of pools where the actual producing rates were approaching rates that might adversely affect recovery. The PRL was to apply until an MER or equivalent study was completed to determine the proper rate or schedule of rates.

The Board expected that most correlative rights considerations would be satisfied by the application of MRLs within the framework of the proration plan, including the rules for production spacing units and the application of GOR and water-oil ratio (WOR) penalties.

3.2 Surveillance of the Effect of Production Rate on Recovery

The surveillance of production rates and performance characteristics of individual wells, leases, and pools has been a continuous undertaking of the Board since its formation in 1938 and particularly since the development of the Leduc and Redwater fields in the late 1940's. At that time individual leases were comparatively small and it was customary to either separately measure individual well production or to distribute the production from the battery to individual wells on the basis of well tests. It was recognized that accurate production data was required for comprehensive engineering studies and that the individual well was the most logical entity for reporting and recording production data. This data file is a key link in the Board's information system and it is used for the surveillance of performance trends in GOR, WOR, and the frequency and occurrence of breakthrough.

The surveillance of the effect of production rate on recovery also requires that basic reservoir properties be known with good accuracy. The Board has encouraged the taking of logs, cores and fluid samples, and has established certain minimum requirements in this regard. In addition, it has promoted the obtaining of special core, PVT and fluid displacement data. These basic reservoir properties are used in the preparation of all engineering studies including those for the specific purpose of assessing rate-recovery sensitivity.

As part of its general surveillance procedure the Board has required that regular bottom-hole pressures and interface measurements be obtained in major pools. It has reviewed these along with trends in production characteristics to assess their sensitivity to production rate and to assess the need for enhanced recovery or the need for revision to the terms or conditions of project approvals.

3.3 Regulation of Production Rate

The regulation of oil, gas, and water production rates from individual wells has also been a continuous undertaking of the Board since its formation in 1938 and particularly since the start of prorationing on December 1, 1950. Some of the factors contributing to the need for regulation of production rate were:

(a) equity considerations caused by diverse ownership of mineral rights,

(b) pressure maintenance was not a common practice and it was recognized there was a need to control production rates from individual wells with adverse performance characteristics to conserve reservoir energy, and

(c) it was recognized that effective regulation of production rate could not be attained on a lease or pool basis and that the basic control entity was the individual well.

Under the original proration plan, the allocation of demand among pools was based on each pool receiving an "economic allowance" for each well in the pool and a share of the residual demand equal to the ratio of the pool's maximum permissible rate (MPR) to the provincial MPR. The total pool MPR was the product of the number of capable wells and the MPR of an average well (based on pool average properties). The total pool allocation could not exceed the pool MPR nor could an individual well allocation exceed the MPR of an average well since acreage distribution was used within pools. There was little flexibility for intra-pool distribution of production under the MPR proration method which required a distribution of the pool allocation to individual wells. Except for

revisions to the economic allowance schedule the MPR method of prorationing and regulation of rates was used until May 1, 1965

Under the current proration plan, increased flexibility is provided for individual well rates by inflation of pool allocations to account for incapable wells and by the introduction of PSUs. The current MRL plan was adopted in 1965 to complement the proration plan since the latter serves primarily as an allocation procedure for distributing the market demand.

Subsequent to issuing Report OGCB 65-3, the Board used the PRL formula as a basis for screening pools or portions of pools to decide whether an MER or equivalent study should be initiated or if other surveillance was required. Until 1970 or 1971, most light- and medium-gravity oil pools had prorated allowables significantly less than the rate limits suggested by the PRL formula. Consequently MER or rate-recovery sensitivity studies were not requested for these pools nor were any received. The situation in the heavy-gravity oil pools was different since they were not subject to prorating and in many instances were producing at capacity. For these pools MER studies were not received, possibly because expensive and detailed engineering studies could not be justified having regard for the low to moderate productivity and the low market value of heavy-gravity oil. Thus, it became common practice to regulate production on the basis of the PRL formula in heavy-gravity oil pools.

By 1973 the proration allowables for many of the light- and medium-gravity pools had increased, or had been inflated by the application of pool incapability factors as part of the mechanics of the proration plan, to the point where the Board judged that conservation objectives could suffer. As a temporary measure these pools were placed under MRL control commencing November 1, 1973. The PRL formula was used to determine interim MRLs for most of these pools. Special engineering studies were available for only a few of the pools and, although these were not comprehensive rate-recovery sensitivity evaluations, they provided a better basis for assigning an MRL than did the PRL formula.

Details of the current method for regulation and administration of production rates from pools subject to MRL are outlined in Part 10 of the Oil and Gas Conservation Regulations. The method provides for acreage distribution of MRLs to production entities and requires application of GOR, WOR and off-target penalties. It has been the practice to disregard off-target penalties in single-well pools and in some multi-well pools where there is common ownership. Penalties are also imposed for overproducing the penalized MRL on a monthly basis, or on a six month balancing basis.

4 HIGHLIGHTS OF SUBMISSIONS

The following summarizes the written submissions and oral testimony of each participant at the hearing. The views of participants with respect to the specific issues identified by the Board are given in more detail later.

4.001 Board Staff

The Board staff submission reviewed the present proration and MRL plans, discussed some qualitative and quantitative MRL considerations, presented a tentative empirical procedure for setting PRLs where rate-recovery sensitivity studies are not available, and proposed a general method for regulation and administration of MRLs.

In its discussion of qualitative MRL considerations, the Board staff defined reservoir waste as the failure to recover or produce oil because of excessive production rates from the pool or individual wells. Pool recovery was considered to be independent of individual-well recovery only to the extent that oil not recovered by one well can and will be recovered by others. The Board staff expressed concern about operating practices that could reduce pool recovery. It was of the opinion that pool high-grading could result in situations where only the better wells were produced although it would be economical to take production more uniformly from all capable wells. The Board staff submitted that any changes to the MRL plan should recognize that: (1) reservoir waste can be caused by excessive production rates at any stage of reservoir depletion, (2) there is a natural tendency for production rate to diminish with cumulative production, (3) MRLs should reflect actual pool performance and conditions and not the performance that could result from changed conditions, (4) reservoir heterogeneity is the principal cause of reservoir waste due to rate-sensitive recovery.

The Board staff reviewed some of the physical phenomena that limit the quantity of oil recoverable by the various drive mechanisms. The dearth of rock wettability and imbibition data was emphasized with regard to the difficulty of obtaining representative capillary pressure

and relative permeability data. The staff stated that numerical reservoir simulation studies should allow for variable rock and fluid properties, including history-dependent capillary pressure and relative permeability, in order properly to assess rate-recovery sensitivity. It opined that the use of idealized boundary conditions, isotropic rock properties, and uniform capillary pressure and relative permeability in numerical simulations could introduce a degree of uniformity that could mask rate-recovery sensitivity effects in otherwise heterogeneous systems.

The Board staff presented an empirical relationship for setting PRLs in those cases where suitable MER or rate-recovery sensitivity studies were not available or were found to be unreliable compared to actual field performance. The initial PRL proposed would be a function of the oil mobility and initial oil in place per acre (a variable that gives a measure of pay thickness). The empirical relationship was structured so that for high mobilities, (greater than those for most oil pools but typical of some gas pools) the initial PRL would be directly proportional to initial oil in place per acre. For these high mobilities, the initial PRL would correspond to a constant-rate life index of one year for all initial oil-in-place values. At the other extreme, initial PRLs would be nearly independent of initial oil in place per acre for oil mobilities less than 1 md/cp. The initial M-factor (a factor intended to give a measure of the ability of a well to produce safely more than its DSU allocation) was taken to be proportional to the logarithm of the product of oil mobility and initial oil in place per acre. It was also proposed that the initial M-factor be systematically decreased with cumulative oil production to encourage the operation of all capable wells in the later stages of depletion.

A general method for regulating and administrating MRLs was proposed by the Board staff. The procedure was adaptable within the framework of the current proration plan. The area to which an MRL would apply was called a maximum rate unit (MRU). Each MRU would consist of any one or a combination of the normal production entities, including PSUs, blocks and projects. The method distributed the MRL to the production entities within each MRU on the basis of acreage.

In this regard, it was similar to the current MRL plan but, unlike the current plan, it would limit production from producing wells in PSUs, blocks and projects to a multiple (M-factor) of the acreage allocation of their drilling spacing unit (DSU). It would apply overproduction penalties for monthly production exceeding the limit for individual wells and for monthly production exceeding the MRL allocation for each production entity. It also provided for application of GOR and WOR penalties on the basis of individual-well production performance. The Board staff believed its method of regulating and administering MRLs would reduce the possibility of individual-well damage that could adversely affect pool recovery, provide a controlled measure of operational flexibility thereby eliminating the need for control-well regulations, and satisfy most equity considerations.

In summary, the Board staff contentions were as follows:

(1) Reservoir heterogeneity is the principal cause of rate-recovery sensitivity.

(2) Operating practices and physical constraints must be considered in rate-recovery sensitivity analysis.

(3) Individual-well production rates require surveillance and regulation.

(4) In the absence of MER studies or other evidence an empirical approach should be used to estimate MRLs.

(5) Administrative procedures should recognize actual pool and well performance.

4.002 Alminex

Alminex Limited is an exploration and development company controlled by Falconbridge Nickle Mines Limited of Toronto. Alminex has crude oil production in Alberta of approximately 6,500 bbl/d, most of it under unit agreement and operated by others.

In its primary submission Alminex stated that Report OGCB 65-3 was still an excellent guide to principles, beliefs and pertinent information and should be considered as the foundation for any further

consideration of MRLs. Alminex considered it necessary to develop an MRL system that, when coupled with other controls such as GOR and WOR penalties, minimum spacing, enhanced recovery requirements, gas conservation requirements and general reporting procedures, would do its part in fostering the maximum economic recovery of the oil resources. It submitted that one of the more serious shortcomings of the current MRL system was its lack of flexibility in allowing for the proper handling of widely varying situations. It stated that the application of a universal formula would not be sound.

Based on its own experience and a literature review, Alminex concluded that water-flooding is generally more efficient at higher oil production rates. This conclusion was based on the presumption that rate sensitivity is chiefly due to imbibition and that only a few reservoirs have wettability characteristics in the range where imbibition is significant.

Alminex proposed that MRLs should be applied only to new pools and where rate sensitivity could be proven significant. Recent allowable levels were considered a general guide to the rate believed most suitable for the new pools. It suggested that more emphasis be placed upon obtaining MER studies so that MRLs could be based on sound engineering principles. It contended that individual-well rate limitations were generally unnecessary and impractical, and should be applied only in extreme cases.

Alminex generally concurred with the extent to which the Board had applied MRLs to pools or parts of pools and to the method of distribution within such entities, and concurred with the time period (monthly allowables and six-month balance) currently employed. Alminex submitted that the MRL system did not have to provide incentives for enhanced recovery, since such incentives were already present. It also pointed out that lease boundary control for equity purposes should not be a consideration in establishing MRLs.

Alminex recommended that the Board staff proposal be rejected since no technical evidence was presented to support the assumtion that rate restriction would improve recovery. It also disagreed with the screening criteria proposed in submissions by Gulf and Imperial.

The following summarizes the points made by Alminex:

(1) Application of a universal formula would not be sound.

(2) The majority of pools do not require MRLs.

(3) Individual-well limitations are unnecessary.

(4) Individual pool studies should be the basis for MRLs.

(5) Acreage is a satisfactory basis for distribution of pool MRLs.

4.003 Amerada

Amerada Minerals Corporation of Canada Ltd. is wholly owned by Amerada-Hess Corporation of New York. It has crude oil production in Alberta of approximately 20,000 bbl/d, primarily from D-3 reef and Cardium sandstone pools.

Amerada stated that numerical simulation studies for the pools in which it was operating had indicated recovery to be insensitive to production rate. It recommended that no consideration be given to the setting of PRLs or MRLs unless based on MERs because the technical data available indicated that rate increases in general did not reduce ultimate recovery. It stated that some pools may have coning tendencies or other conditions that would require pool MER or individual-well rate limitations.

Amerada intervened with respect to the Board staff submission, stating that the premise that recoveries would be improved as a result of MRLs was not documented by any factual or technical data.

In summary, Amerada made the following points:

(1) Available technical data and its own studies indicate that rate increases in general do not reduce ultimate recovery.

(2) No consideration should be given to the setting of PRLs or MRLs unless based on MERs.

(3) Some pools may have conditions that require rate restrictions.

4.004 Amoco

Amoco Canada Petroleum Company Ltd. is a major exploration and producing company, and a wholly owned subsidiary of the Standard Oil Company of Indiana. It has crude oil production of some 80,000 bbl/d from the major carbonate- and sandstone-producing regions in Alberta.

Amoco did not tender a primary submission but in its intervention stated that except for some possible coning situations, individual-well rates would have a negligible effect on recovery. It contended that in pattern displacement projects operators required complete flexibility to set individual-well rates, to attain maximum recovery. Amoco was of the opinion that the present allowable and MRL system was equitable, since it promoted reasonably uniform project lives.

With respect to the Board staff proposal, Amoco contended that the proposed PRL formula was technically unsubstantiated and that no single, simple formula could describe the effects of producing rate on ultimate recovery. It stated, and showed by way of an example, that in some cases the proposed MRL regulation procedure could discourage implementation of enhanced recovery or development of marginal areas. Amoco questioned the Board staff's premise that, with the absence of good data and other uncertainties, it would be prudent to apply rate limitations. It argued that in the face of uncertainties, it could be better to increase producing rates than to restrict them.

In summary, the Amoco position was as follows:

(1) Pattern displacement projects require complete flexibility of well rates to attain maximum recovery.

(2) The Board staff's proposal should be rejected.

4.005 Aquitaine

Aquitaine Company of Canada Ltd. is controlled by Societe Nationale des Petroles d'Aquitaine of France. Its Alberta oil production is primarily from Devonian reefs in the Rainbow Field and amounts to approximately 30,000 bbl/d.

In its response to the Board staff submission, Aquitaine submitted that producing rates from oil pools should be determined by the principles corresponding to the Board's Regulations for good production practice. It suggested that a pool reference rate related to the recovery mechanism or pool type, be established for surveillance of operator production practice. Aquitaine proposed that an operator should be able to exceed or redefine the pool reference rate without penalty provided he could justify his particular production practices. Otherwise, the Board could impose GOR, WOR or overproduction penalties to avoid specifically wasteful practices. Aquitaine was opposed to rigid application of any formula that would restrict the opportunity to evaluate pool capability and performance at higher rates.

The company submitted that the Board staff's premise that MRLs should be applied to prevent reservoir waste was not substantiated. It questioned the logic of the proposed PRL formula and recommended that it not be used to set MRLs or reference rates for pool surveillance.

In summary, Aquitaine submitted that:

(1) GPP should be extended to most pools,

(2) a pool reference rate could be set for each pool to assist in surveillance of production practices, and

(3) the Board staff's proposal should be rejected.

4.006 Ashland

Ashland Oil Canada Limited is an exploration and producing company controlled by Ashland Oil Inc. of Kentucky. Ashland has approximately 16,000 bbl/d of oil production in Alberta, most of which comes from water-flood projects in sandstone reservoirs.

For horizontal water-floods in sandstone reservoirs, Ashland proposed that no restrictions be placed on rate provided all reservoir voidage be replaced, that voidage replacement be required pattern by pattern on a monthly basis, and that injection pressures be set for each reservoir, consistent with good engineering practice. For primary depletion operations in horizontal sandstone reservoirs, Ashland proposed that the existing PRL formula be retained to establish rates

until water-flooding was initiated.

An engineering study prepared and supported by Neotechnology Consultants Limited was concerned with evaluating the effect of rate on recovery from horizontal water-floods and was the technical basis for the Ashland position.

Neotec indicated that the efficiency of water-flooding was influenced by reservoir heterogeneity, mobility ratio, relative permeability, capillarity, rock wettability, imbibition, gravity segregation, coning, frontal instability or viscous fingering, and by the price of crude oil relative to the cost of operation. It submitted that computer models provided the best method of evaluating the effect of production rate on ultimate recovery. Neotec stated that the reliability of any computer model study depended on reservoir rock and fluid data (including reservoir geometry, boundary behaviour, heterogeneity, and the effect of pressure on reservoir and fluid properties), the formulation of the fluid-flow equations, and the approximations used to solve them.

Neotec concluded that incomplete information about the reservoir and its fluid caused the greatest amount of difficulty and could render predictions unreliable. It pointed out that if relative permeability and capillary pressure data were representative of the actual fluid-solid system being considered, then the fluid-flow equations, developed from a combination of Darcy's Law and conservation of mass, were adequate for all engineering studies. Neotec noted that wettability of a reservoir was an important factor influencing capillary pressure and relative permeability data. It stated that no standard procedures are available to assure that laboratory-measured curves were representative of conditions existing in the reservoir.

Neotec stated that research over the past 20 years had resulted in the approximate solution of fluid-flow equations by numerical techniques that may be used with confidence.

Neotec performed a series of calculations to evaluate rate sensitivity of horizontal water-flooding in sandstone reservoirs. Predictions were made using a three-phase, two-dimensional radial-flow model. Several multi-rate runs were made to investigate the effect of

various rock properties and variations in capillary pressure and crude oil viscosities. Higher rates, greater heterogeneity, and higher viscosity all contributed to earlier breakthrough of injected water. Recovery to the economic limit, however, was invariably higher for the higher-rate cases although the higher rates were accompanied by substantial increases in volumes of produced water. Capillary pressure played only a minor role and tended to decrease recovery, except for layered systems produced at low rates.

In its intervention with respect to the Board staff's submission, Ashland noted that no evidence was presented to show that the Board staff's proposal, or reduced rates in general, would increase ultimate economic recovery. Ashland submitted that any proposal should have sound technical back-up.

In summary, the Ashland position was:

(1) Horizontal water-floods in sandstone reservoirs should not be restricted by MRLs, provided all reservoir voidage is replaced on a pattern basis subject to maximum injection pressure limits.

(2) Numerical simulation studies provide a reliable basis for assessing rate-recovery sensitivity.

(3) Numerical simulation studies of horizontal water-floods indicate that predicted ultimate recovery either increases or is independent of production rate.

(4) The Board staff's proposal should be rejected.

4.007 Atlantic Richfield

Atlantic Richfield Canada Ltd. is a wholly owned subsidiary of Atlantic Richfield Company of California. It has oil production in Alberta of some 25,000 bbl/d primarily from Cretaceous sandstone and Beaverhill Lake reef reservoirs.

Atlantic Richfield stated that any PRL formula method adopted by the Board should be used only as a surveillance device and that penalties should be applied only in the event of unsatisfactory reservoir performance. It submitted that MER studies should be the basis for

establishing rate limitations, where these were deemed necessary, and that sound engineering should not be compromised for ease of administration.

With respect to the Board staff's submission, Atlantic Richfield questioned the validity of establishing MRLs by means of a single formula. It disagreed with the proposed procedure for regulation of individual-well rates since, in its view, the procedure did not give proper treatment to well spacing and reservoir heterogeneity in bottom-water drive pools that have water coning tendencies.

In summary, the following points were made by Atlantic Richfield:

(1) Any PRL procedure should be used as a surveillance device and base rate for application of penalties only in the event of unsatisfactory performance.

(2) A single formula is unsatisfactory for establishing MRLs.

(3) The Board staff's proposal is inadequate for estimating and administrating MRLs.

4.008 CPA

The Canadian Petroleum Association is a trade organization with the principal objectives of establishing better understanding between the petroleum industry and the public, and encouraging co-operation between the petroleum industry and government and other authoritative bodies. Its membership is responsible for approximately 97 per cent of Canada's oil and gas production.

CPA did not file a primary submission, but intervened with respect to the Board staff's submission. It submitted that there was no technical evidence in the Board staff's submission that application of its MRL procedure would improve ultimate recovery. Moreover it stated the proposal would not give impartial treatment to all pools, since MER studies would be required by operators of some pools to justify current and planned future rates. CPA stressed that adoption of the Board staff's proposal would have an adverse economic impact on all phases of the industry, on Provincial royalties and on the Canadian balance of payments. It

estimated that universal application of the Board staff proposal would reduce Provincial oil production by over 300,000 bbl/d. In those pools where MRLs were deemed necessary, CPA recommended that MER studies be given preference over any formula approach and that until an alternative system was developed the current MRL procedures be used as a surveillance device only,

The CPA position was as follows:

(1) The Board staff's proposal should be rejected.

(2) MER studies should be used to determine MRLs in those pools where they are deemed necessary.

(3) The present MRL procedure should be used only as a surveillance device.

4.009 Canus

Canus Petroleum Limited is an independent exploration and producing company with Alberta oil production of some 1,500 bbl/d from small pinnacle reefs in the Zama field.

Canus submitted that the Board staff's PRL procedure may be satisfactory where the data input to the calculation were reasonable and accurate. It stated from experience, however, that reserve estimates and other data were not very accurate and therefore it would prefer not to have wells subject to MRLs but only to good operating practice, with individual well rates adjusted to reflect actual production performance. Canus emphasized that the rates required for satisfactory return and payout of completion and operating cost often exceeded calculated MRLs or minimum allowance schedules.

In summary, the following points were made by Canus:

(1) GPP should be extended to more pools.

(2) In some cases MRL procedures should be set aside because of economic considerations.

4.010 Chevron

Chevron Standard Limited is a major exploration and producing company wholly owned by Standard Oil Company of California. Its Alberta oil production comes from the major carbonate- and sandstone-producing regions of the province and amounts to some 100,000 bbl/d.

Chevron intervened with respect to the Board staff's submission and contended that ultimate recovery from all pools was not rate-sensitive within the normal range of pool production rates experienced in Alberta. It submitted that in pools that may experience reduced recovery at excessively high rates, the type of drive or recovery mechanism was most important and therefore a single formula was inadequate for estimating MRLs. It questioned the validity of using an empirical procedure and historical data to estimate MRLs. Chevron disagreed with the Board staff's procedure, which would limit individual-well rates, since it contended that it was not necessary to restrict individual wells subject to coning, particulary during the subordinate phase of production.

Chevron recommended that the practice of assigning MRLs by formula be discontinued. In those pools where MRLs were deemed necessary and where detailed studies were not available, it proposed that engineering judgement be used having regard for actual pool performance.

In summary, the Chevron position was as follows:

(1) Within the normal range of pool production rates, recovery from most pools is not sensitive to rate.

(2) It is not necessary to restrict individual wells subject to coning.

(3) Engineering judgement rather than empirical formulae should be used to set MRLs in those pools where MRLs are deemed necessary.

4.011 D&S

The submission by D&S Petroleum Consultants Ltd. was made on behalf of Bumper Development Corporation Ltd. and Andex Oil Co. Ltd., both independent exploration and producing companies with a significant

interest in the Twining Rundle A Pool.

D&S emphasized that the Twining Rundle A Pool was a low reserve-per-acre pool which was still not fully developed although the discovery well was drilled in 1952. The slow development was attributed to low economic incentive because of depressed allowables under proration, and to MRLs and regulations that prevent the transfer of allowables between wells. D&S submitted that there was no need to restrict production rates during pool development and that without rate restrictions the increased economic incentive would assure rapid development and encourage early implementation of an enhanced recovery project.

D&S used a three-phase radial coning model to study well performance for conditions typical of the Twining Rundle A Pool. The sensitivity of primary recovery was evaluated with respect to the relative position of two layers of different permeability, the vertical permeability, and the reservoir voidage rates. The model runs indicated that the relative position of layers with different permeability had a significant effect on oil recovery. When the less permeable layer was on top, the solution gas drive mechanism was supplemented by a more efficient drive mechanism due to gravity segregation of gas. The effectiveness of gravity segregation was observed to improve with increased vertical permeability. It was also observed that production rate had a negligible effect on primary recovery when the less permeable layer was on top, but that increased production rates resulted in increased recovery when the less permeable layer was underneath.

In oral testimony it was submitted that future oil discoveries in Alberta were likely to be of lower quality than in the past and that, under present MRL procedures or the Board staff's proposed procedures there may not be sufficient economic incentive to continue to explore for and develop such pools. It was noted that recent developments had made the development of gas reserves more profitable than the development of oil reserves.

In summary, D&S submitted the following:

(1) There is no need to restrict production rates during pool development.

(2) A numerical simulation study has indicated that predicted oil recovery is very sensitive to the relative position of layers of different permeability and that increased production rates result in increased recovery.

(3) Low-quality pools require special condiseration to assure there is sufficient economic incentive for exploration and development.

4.012 Dome

Dome Petroleum Limited is an independent exploration and producing company with a special interest in processing and marketing natural gas liquids. Its crude oil production in Alberta is primarily from pools in Cretaceous sandstones and small pinnacle reefs and amounts to some 5,000 bbl/d.

Dome supported the IPAC submission and emphasized the need for incentives to encourage enhanced recovery projects and development of low-reserve pools with high productivity. Dome stated that the present PRL formula could be used during the early life of a pool but that a single formula could result in inequities because of the wide range of oil reservoirs found in Alberta. It recommended that MRLs be based on individual pool engineering studies where sufficient data were available and stated that MRLs may not be necessary for pressure maintenance projects since it believed that a balance of injection and withdrawals should be the main criterion for reservoir control. Dome opined that GOR or WOR penalties provided the necessary control over rates in primary operations or where problems developed with a particular drive mechanism.

In summary, Dome submitted the following:

(1) The present PRL formula with GOR and WOR penalties provide the necessary rate control for new pools and primary depletion areas.

(2) Individual pool studies are required for proper evaluation of the need for or level of any MRL.

(3) Pressure maintenance projects may not need MRLs.

4.013 Great Plains

Great Plains Development Company of Canada, Ltd. is a production and exploration company controlled by The Burmah Oil Company Limited of London*. Its Alberta oil production is primarily from Cretaceous sandstones and Mississippian carbonates, and amounts to some 8,000 bbl/d.

Great Plains proposed that no MRLs be set for horizontally waterflooded pools (assuming voidage replacement and strict control of GORs) or for reservoirs with vertical displacement mechanisms (assuming pressure to be fully maintained). It stated that the imposition of generalized MRLs would be an ineffective method of controlling reservoir waste since it believed ultimate recovery to be more sensitive to the recovery mechanism than to the production rate. Moreover, it stated each pool's rate sensitivity, if any, to be different and undeterminable by an MRL formula. It pointed out the need for economic conservation in MRL considerations since, if physical conservation were the only criterion, it would follow that a pool should be shut in until a process was developed to guarantee 100 per cent recovery.

Great Plains stated that, from a reservoir mechanics aspect, ultimate recovery from a pool was not rate sensitive. This position was supported by a technical study prepared by Intercomp Resource Development and Engineering Ltd. Intercomp defined sensitivity to rate as ultimate economic recovery being adversely affected by increasing withdrawal rates. It used multi-dimensional, multi-phase reservoir models to investigate the sensitivity of oil recovery to production rate for several types of reservoirs found in Alberta. For the cases studied, increased oil recovery was predicted for the higher producing rates.

Imbibition phenomena were studied in two cases, using basic reservoir data from some Belly River sandstones. In one case, rates of imbibition into a cylinder of rock from a free water interface were simulated. The runs showed that complete cocurrent imbibition was obtained in 70 days for water-wet rocks of commercial interest. In another case, a vertical cross-sectional model of a hypothetical reservoir was used to simulate countercurrent imbibition against a gravity force. The upper

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*Since the time of the hearing Great Plains has been purchased by Canadian Industrial Gas and Oil Ltd.

layers of the cross-section had zero horizontal permeability such that oil could be recovered from them only by countercurrent imbibition into a more permeable bottom layer. From these cases it was concluded that imbibition times were small compared to field depletion times, and that numerical models were capable of correctly modelling imbibition phenomena.

A two-dimensional coning model was used to model the performance of a producing well from a horizontal water-flood project in a Beaverhill Lake carbonate. The reservoir oil was undersaturated and reservoir pressure was assumed to be fully maintained by injecting water along the outer full face of the model. Capillary forces were not considered in these runs and, using a limiting oil rate of 5 bbl/d, the results indicated slightly increased recovery at the increased production rates. The effect of drawing the well down below the bubble point and causing gas saturation around the well bore was investigated by making another run at reduced reservoir pressure. This run indicated that gas saturation soon stabilized at the value of the critical gas saturation and neither reduced recovery nor seriously impaired oil mobility.

A coning model was also used to study the performance of a single well in a Keg River reef reservoir with full pressure maintenance by bottom-water influx. Runs were made for homogeneous and stratified reservoir rock configurations, using capillary pressure and relative permeability relationships considered to be characteristic of water-wet and of oil-wet rock systems. In all cases the higher rate runs had higher recovery.

A series of runs was made using a coning model to simulate the performance of a well completed in a Mannville sandstone containing viscous oil and underlain by water. Complete pressure maintenance was assured by full-face water injection into all layers at the outer boundary. Runs were made using different fluid production rates, oil viscosities, capillary forces, reservoir permeabilities, completion intervals, and oil-relative permeabilities. In all runs the production rate had virtually no effect on calculated water-oil ratio performance and the effect of increased rate was to increase the predicted oil recovery.

The effect of water coning on oil recovery from Devonian reef wells in pools with active bottom-water drives was studied, using a

coning model. Two different cases were studied and several runs were made to investigate the sensitivity of well performance to capillary forces, flow barriers, reduced absolute permeability, adverse relative permeability, reservoir stratification, and heterogeneity. The tendency to cone was increased by inclusion of capillary forces, reduced absolute permeability, adverse relative permeability, and random heterogeneities. However, in all runs, somewhat increased oil recoveries were calculated for increased fluid production rates.

The sensitivity of recovery to production rate in a Belly River sandstone subject to horizontal water-flood was studied using two different models. Several multi-rate runs were made using a vertical cross-section model employing different relative permeability relationships for each of four ranges of absolute permeability. These runs investigated the sensitivity of cross-current imbibition to capillary pressure and layer thickness and the effect of grid definition, anisotropy, and selective completion on ultimate economic recovery. It was observed that the predicted oil recovery was not adversely affected by increased rates in any of these cases. Other runs were made, using capillary pressure relationships characteristic of water-wet, then oil-wet, rocks. Significantly higher oil recovery was predicted at higher flood rates for both the water-wet and oil-wet systems. The effect of areal heterogeneity on the sensitivity of recovery to fluid production rate was studied using a three-dimensional model. This model represented a one-eighth unit of symmetry from a 9-spot pattern. For the two runs made, areal heterogeneity had a small effect and increased oil recovery was calculated for increased fluid production rates.

With respect to the Board staff's submission, Great Plains disagreed with many of the concepts and recommended that it be rejected. It contended that, since the Board staff did not prove the initial PRL correlation to be based on efficient rates, it was simply a productivity correlation, which would tend to restrict the productivity of the better pools to the level of the lower-quality pools. It stated that the logic between the M-factor and MRLs was inconsistent since the M-factor would permit initial production rates of up to six times the average for the

MRU. It questioned the soundness of the procedure since no technical evidence was given to justify the relationship of the M-factor to oil mobility and initial oil in place. The use of the coefficient of permeability variation to decrease the M-factor with cumulative production was also questioned, since no technical evidence was provided.

In summary, the Great Plains position was as follows:

(1) No MRLs be set for pools with horizontal water-flood.

(2) No MRLs be set for vertical-drive pools with full pressure maintenance.

(3) Producing rate does not have an adverse effect on ultimate economic recovery.

(4) The Board staff's proposal should be rejected.

4.014 Gulf

Gulf Oil Canada Limited is a fully integrated oil company controlled by Gulf Oil Corporation of Pittsburgh. Its crude oil production in Alberta is primarily from the major carbonate-producing areas in the province and amounts to approximately 95,000 bbl/d.

Gulf was of the opinion that neither pool nor well rate limitations should be imposed unless production at capacity could be reasonably established to be detrimental to either ultimate recoverable reserves or correlative rights.

A general review of the most important factors influencing the effect of pool depletion rate on oil recovery operations was presented by Gulf. These factors included pool productive capability, drainage by radial flow to wells, reservoir wettability, reservoir stratification, coning, and remaining reservoir energy. Gulf stated that the reservoir stratification factor became important only when the variance in pore volume opposes the variance in flow capacity such that a displacing fluid will flow preferentially, at high velocity, through bands containing relatively small volumes of oil.

Gulf submitted that producing rate limitations can be expected to affect the ultimate oil recovery only in specific pools subject to certain reservoir production mechanisms. It stated that in such cases,

the degree to which producing rates were limited should be based, not on the current degree of depletion, but on the subsisting pool energy level as determined by pressure. In addition, it proposed that any rate limits be administered on an individual-well basis for these pools.

A formula for the control of individual-well rates was proposed by Gulf. The formula was designed for administrative simplicity and included only those reservoir parameters that Gulf felt might affect oil conservation. These parameters included permeability, formation thickness, oil viscosity, well and drainage radii, and pressure drawdown. Gulf stated that where the Board felt these individual well rates required better definition, a comprehensive MER study could be requested. Gulf expressed the opinion that such a study should take precedence over an MRL assigned by a generalized formula.

Gulf also submitted that in the administration of a maximum rate limitation scheme, pools should be subdivided into producing areas having common reservoir quality and displacement mechanism. It felt that the concept of maximum rate units could be applied provided that correlative rights were not endangered.

Gulf submitted that the Board staff's proposal should be set aside since it was not demonstrated that the proposal would result in improved oil conservation. It contended that the empirical formula used parameters having little significane with respect to ultimate recovery.

The following summarizes the position of Gulf:

(1) MRLs should not be imposed unless production at capacity reasonably could be established to be detrimental to either recovery or correlative rights.

(2) Reservoir stratification is important in MRL considerations only when pore volume is disproportionately related to flow capacity.

(3) Where MRLs are required, they sould reflect the subsisting pool energy and not the stage of depletion.

(4) Surveillance and regulation of individual-well rates based on factors significant in well production performance and on subsisting reservoir energy should be carried out. A specific method was proposed for this.

(5) Except for some provisions relating to MRUs, the Board staff proposal should be set aside.

4.015 Home

Home Oil Comapny Limited is an exploration and production company controlled by The Consumers Gas Company of Toronto. It has about 32,000 bbl/d of oil production in Alberta, primarily from the Swan Hills area.

Home submitted that oil recovery from heterogeneous reservoirs was largely insensitive to production rate insofar as microscopic displacement efficiency was concerned. It claimed that increased production rates would lead to increased ultimate economic recovery of oil because of the interrelationship among recovery, production rate, and economic limit. This claim was supported by two-dimensional, two-phase model runs for two reservoir cross-sections simulating reef rim and reef lagoonal developments within the Swan Hills Beaverhill Lake A and B Pool. The model runs indicated increased ultimate economic oil recovery for increased production and injection rates. In view of the foregoing, Home suggested that the concept of applying some form of MRL system to control individual-well producing rates in the hope of increasing ultimate oil recovery would be invalid.

Home contended that the Board could continue to promote conservation and prevent waste without the use of an MRL system. It was of the opinion that the Board could fulfil this responsibility by applying a thorough surveillance procedure and by initiating corrective action, where necessary, to effect conservation. Home suggested that if the Board decided there was a need for an MRL system it was unlikely that a universal MRL formula could be developed to apply properly to all situations. Instead, Home suggested that a joint Board - Industry Committee develop a series of relationships that would recognize differences among reservoirs and among various drive mechanisms. Home stated that such an MRL system should be able to provide the Board with the means for identifying potentially wasteful situations. Once the situation had been identified, the Board could resolve the problem by using

existing procedures such as private consultation with the operator or the issuance of various orders.

Home was of the belief that an MRL system should provide for the granting of an MER or GPP status to pools or projects where an adequate submission by the operator had been made. It also stated that the system should not be used to protect correlative rights within a pool, but that if protection of correlative rights was required it should be accomplished by some other means.

Home further stated that an MRL system should not restrict production to some uniform rate per well within a pool. It opined that, for most reservoirs, producing rate flexibility would result in maximum economic worth without loss in ultimate oil recovery and that to operate in any other manner would result in economic waste and could lead to a loss of reserves.

It was recommended by Home that any revised MRL system be implemented in phases commencing on January 1, 1976, in order to prevent undue economic hardship. Home suggested that the present PRL system be retained in the interim period.

Home intervened with respect to the Board staff's submission and disagreed with the basic philosophy that increased oil production rates would tend to reduce ultimate recovery. It was of the opinion that MRLs reduced economic incentives for activities such as well reworks and infill drilling which can result in increased oil recovery. Home questioned the logic of the Board staff's proposal and submitted that "ease of administration" and "uniformity of treatment" were not sufficient reasons to justify development of generalized MRL procedure.

The following summarizes the points made by Home:

(1) Its studies indicated that increased production rates in heterogeneous reservoirs would result in increased ultimate oil recovery.

(2) An MRL system is not necessary to promote conservation and prevent waste.

(3) A single MRL formula could not properly apply to all situations but a series of MRL relationships could be helpful for surveillance purposes.

(4) An MRL system should not be used to protect correlative rights.

(5) An MRL system should not restrict individual-well rates because it would cause economic waste and could reduce ultimate recovery.

(6) If adopted, a revised MRL system should be implemented in phases to prevent undue economic hardship.

(7) The Board staff's proposal should be rejected or significantly revised after consultation with industry.

4.016 Hudson's Bay

Hudson's Bay Oil and Gas Company Limited is an exploration and development company controlled by Continental Oil Company of Delaware. It has oil production distributed throughout all producing regions of Alberta amounting to about 46,000 bbl/d.

Hudson's Bay contended that ultimate recovery in most pools was not significantly affected by production rate variations within economic and practical ranges. However, it acknowledged that an MRL may be desirable during the initial stage of development of certain pools to prevent excessive waste of reservoir energy.

Since the notice of hearing indicated that the Board expected to continue applying maximum rate limitations, Hudson's Bay proposed that, as a first stage in the control of production rates, the use of the current PRL formula be continued. However, it stated that a universal formula for maximum rate limitations would not determine fairly the appropriate production rates for the wide diversity of oil reservoirs in Alberta. Therefore it proposed that operators be required to submit to the Board a depletion plan for the optimum economic recovery of a pool. Hudson's Bay suggested that the optimum production rates determined for the plan supersede those determined by the current PRL formula.

Hudson's Bay preferred the current MRL formula as opposed to a more restrictive formula. It submitted that the immediate imposition of a restrictive MRL formula, which would encourage the submission of MER studies to increase the MRL, would result in a reduction in the quality of the studies being performed.

Hudson's Bay also proposed that, in order to provide the operator with maximum flexibility in attempting to attain the maximum economic recovery, MRLs not be applied to heavy-gravity crude oil pools.

In its intervention, Hudson's Bay submitted that a universal MRL formula could not be developed and that only individual pool studies would assess properly all the parameters affecting reservoir performance and ultimate recovery.

In summary, Hudson's Bay made the following points:

(1) The ultimate recovery from most pools is not significantly affected by production rate.

(2) A universal formula would not fairly set MRLs for the wide diversity of oil reservoirs.

(3) As an alternative to a formalized MRL procedure, operators could submit a depletion plan for the optimum economic recovery from a pool.

(4) Immediate imposition of a restrictive MRL procedure where MER studies are not available would reduce the quality of the studies submitted for MRL considerations.

(5) Heavy-gravity crude pools should not be subject to MRLs.

4.017 Husky

Husky Oil Operations Ltd. is part of a fully integrated oil and gas enterprise with special interest in heavy-gravity crude oil. It has oil production in Alberta amounting to about 10,000 bbl/d.

In its submission, Husky was concerned only with the application of MRLs to heavy-gravity crude oil production. It expressed the opinion that the imposition of one general formula to all Albertan oil production would not serve its intended purpose.

Husky requested that the Board establish a well MRL of 50 bbl/d for all wells producing crude oil with an API gravity of 20° or less. Its production experience in Saskatchewan indicated that the proposed rate would not affect the ultimate recovery from pools having comparatively low initial reservoir energy. Husky stated that any sophisticated final recovery scheme suitable for application to this type of

pool (such as in situ combustion) would be entirely independent of recovery of primary depletion and, as such, independent of any possible rate effect.

Husky contended that production rates from heavy-gravity crude oil pools were limited more by well bore and operational problems than by the flow phenomena in the bulk of the reservoir. It further contended that a minimum MRL in the order of 50 bbl/d would be required to provide the incentive for the exploration for and development of additional heavy-oil reserves.

In summary, the Husky position was as follows:

(1) One general MRL formula would not serve its intended purpose.

(2) A well MRL of 50 bbl/d should be set for heavy-gravity oil pools.

(3) Sophisticated recovery schemes for heavy-gravity oil reservoirs are not affected by any primary rate-recovery sensitivity effects.

4.018 Imperial

Imperial Oil Limited is controlled by Exxon Corporation of New York and is the largest fully integrated oil company in Canada. It has crude oil production of some 250,000 bbl/d from the major carbonate- and sandstone-producing regions in Alberta.

Imperial stated that reservoirs should not be produced at rates that could lead to a reduction in the recovery otherwise obtainable from the application of sound engineering and economic principles. However, it contended that MRLs were required only in exceptional situation, where a change in the displacement mechanism could occur if production rates were increased.

Imperial recommended that a general formula such as the existing PRL formula be used, not to set MRLs for pools, but to serve as a surveillance tool to identify those pools possibly requiring MRL restriction. An alternative means of surveillance to determine when an operator's depletion plan for a pool needed review was also submitted. The rationale behind this proposal was that from the standpoint of ultimate

pool recovery, there was no need for rate restriction so long as there were sufficient economic incentive remaining to support the replacement of wells whose abandonment, without replacement, could result in a reduction in ultimate recovery from the pool. Should an MRL be required, Imperial strongly urged that an individual pool study form the basis for establishing the MRL.

In assessing the relationship between producing rate and ultimate recovery, Imperial differentiated between the sensitivity of individual-well performance to producing rate and the sensitivity of ultimate recovery from a reservoir to total reservoir withdrawal rates. It was Imperial's opinion that only some unique set of reservoir characteristics and economic conditions could lead to a loss in recovery because of individual-well rates.

Imperial investigated the possible impact of pool or well rates on the ultimate recovery of water displacement processes by using multi-dimensional, multi-phase mathematical models of various carbonate rock systems. The model results showed better recovery as producing rates increased because of greater water throughput prior to reaching the economic limit. Included in the model runs was a comparison of recoveries from homogeneous and heterogeneous systems. The predicted recoveries were lower for the heterogeneous than for the homogeneous systems; however, greater recoveries at increased producing rates were predicted for both.

Imperial also studied the sensitivity of recovery to rate for a homogeneous matrix containing varying numbers of "tight" lenses with significantly reduced horizontal and vertical permeability values. The results of the model runs indicated that the position of the lens in the homogeneous matrix and the magnitude of the lens permeability determined whether the rate would have a beneficial or detrimental effect on oil recovery from the lens. The recovery from the entire system was improved at increased rates because of greater water throughput through most of the system. This effect tended to offset the slight reduction in recovery from some of the tight lenses.

The only case for which Imperial's simulation runs indicated that recovery was improved by reduced rates was for a vertical cross-section

model with continuous thick (15.6 ft.) low-permeability layers sandwiched between thick high-permeability ones. In this example, complete drainage by imbibition from the low-permeability layers did not occur prior to reaching the economic limit. By the selective variation of viscous, capillary, and gravitational forces, Imperial demonstrated that for such a model the effects of viscous flow predominate in the recovery of oil.

A coning model was used to investigate the effect of rate on recovery for an oil-wet system and the effect of increasing rates at the terminal stage of depletion. For this system, greater recovery occurred at increased rates due to greater water throughput. The absolute recoveries for the oil-wet systems were lower than those for the comparable water-wet systems. A portion of this study showed that the ultimate recovery achieved under a schedule of progressive rate increases was less than that for the case where no rate restrictions were imposed at any stage of depletion.

Imperial evaluated the effect of individual-well rate restrictions and differential depletion due to selective withdrawal patterns with cross-section and areal models. From these studies it concluded that selective withdrawal patterns do not cause a loss in ultimate recovery and that the MRU concept proposed by the Board staff should not be applied to individual pools subject to a common mechanism.

Imperial also studied the performance of a slightly-dipping Beaverhill Lake cross-section (in which the role of gravity segregation would be enhanced) for cases using selective production and injection intervals. In addition to noting improved rates, Imperial observed higher recoveries for cases with full-face completions than with selective completion intervals.

In order to check the reliability of its mathematical simulator in describing the imbibition process, Imperial developed a model of the system described by Mattax and Kyte[16]. From these studies, it was concluded that the rate of imbibition occurring in Imperial's mathematical simulator was reasonable and that the imbibition process for a relatively low-permeability lens would be complete within the practical field life.

Imperial also investigated the possible impact of pool or well rates on the ultimate recovery of water displacement processes by making

detailed performance analyses for four pools: Redwater D-3, Excelsior D-2, Judy Creek Beaverhill Lake A, and Judy Creek Beaverhill Lake B. No detrimental effect of producing rate on recovery was observed in any of these analyses. A net energy balance analysis also indicated it was practical to cycle large volumes of water in these pools.

Imperial recommended that the proposals related to determination and application of PRLs contained in the Board staff MRL submission be rejected. It contended that the parameters considered by the Board staff in developing its proposed MRL formula were not appropriate for assessing the effect of rate on recovery. Furthermore, it noted that the proposed formula had not been developed from a consideration of the phenomena which the Board staff considered significant in assessing the degree to which recovery was sensitive to producing rate; namely, imbibition, gravity drainage, interface stability, and reservoir heterogeneity.

Imperial disagreed with the Board staff's M-factor procedure for regulation of individual-well rates, since it concluded there was no need for control-well allowables, particularly in bottom-water-drive or gas-cap-drive pools. It stated that the additional flexibility resulting from the removal of these allowables would allow more efficient reservoir management and improved ultimate recovery.

In summary, the Imperial position was as follows:

(1) MRLs are required only in exceptional cases where a change in displacement mechanism could occur if rates were increased.

(2) A surveillance procedure was proposed based on the premise that there is no need for MRLs provided there is sufficient economic incentive to replace those wells whose abandonment could reduce ultimate recovery from the pool.

(3) Individual pool studies should form the basis for establishing any MRLs.

(4) Some unique set of reservoir characteristics or economic conditions would be required before pool recovery could be reduced, because of high individual-well rates.

(5) Numerical simulation studies for a variety of conditions have indicated that ultimate recovery increases with increased rate irrespective of reservoir heterogeneity, wettability or completion practice.

(6) The Board staff's proposal should be rejected.

4.019 IPAC

The Independent Petroleum Association of Canada is a trade organization representing the independent sector of Canada's petroleum industry.

IPAC expressed the opinion that no universal MRL formula could adequately account for the unique characteristics of each reservoir in the province of Alberta. Consequently, it recommended that the MRL for a pool be based on individual pool engineering studies rather than on a general formula. IPAC stated that it would be prepared to accept the continuation of the present PRL formula as a surveillance device until each pool study was completed.

IPAC recommended that, prior to implementing any modification to the MRL system, a joint Board - Industry Committee should be set up to review the proposal and to determine its impact on production from the province. It stated that any modification should continue to provide adequate incentive to implement enhanced recovery schemes. IPAC also stated that any significant changes in the MRL system should be phased in to prevent undue economic hardship.

In summary, the IPAC position was as follows:

(1) A universal MRL formula would not adequately account for the unique characteristics of each reservoir.

(2) MRLs should be based on individual pool engineering studies; however, the present PRL formula would be a satisfactory surveillance device until each pool study was completed.

(3) Any modifications to the present MRL system should be reviewed by a joint Board - Industry Committee and then phased in to prevent undue economic hardship.

(4) Any revised MRL plan should provide adequate incentive to implement enhanced recovery schemes.

4.020 D.R. McCord

D.R. McCord and Associates, a division of University Computing Co., is a group of professional personnel which supplies technical services to all phases of the petroleum industry. McCord has several numerical reservoir simulators and has a special interest in compositional simulators.

McCord questioned some of the assumptions used in the numerical simulation studies performed by Intercomp. It emphasized that consideration should be given to the effects of changing reservoir fluid composition on oil viscosity and density.

4.021 Mobil

Mobil Oil Canada, Ltd. is a major exploration and producing company wholly owned by Mobil Oil Corporation of New York. Mobil has crude oil production from most regions of the province amounting to some 93,000 bbl/d.

Mobil expressed the opinion that there was a relationship between ultimate recovery and the degree of heterogeneity in a reservoir and that reservoir heterogeneity could be the principal cause of low ultimate recovery. It stated that there was no evidence indicating that such low ultimate recovery would be further reduced as a result of high production rates nor that an MRL plan should recognize the importance of reservoir heterogeneity in determining safe maximum rates.

Mobil acknowledged that under certain conditions the ultimate recovery from a pool could be affected by the production rate. It submitted that the sensitivity of recovery to rate could be established only by considering the characteristics of each particular pool. It stated that since a general PRL formula could not incorporate pertinent reservoir characteristics and reservoir history, a general PRL formula should not be used to restrict production prior to determining an MER. Mobil stated that a PRL formula would serve better as a surveillance device to determine when a comprehensive MER study for a pool was required.

As an alternative to the PRL formula, Mobil proposed the use of a Conservation Surveillance Index (CSI) based on the pool life index. The CSI would be selected by the Board as a minimum life index (six to eight years was suggested) for all pools in the Province. Mobil suggested that pools with a constant-rate life factor less than the CSI be considered for an MER review.

Mobil recommended that the Board staff's proposal be rejected. It disagreed with the concepts that reservoir waste could be caused by excessive rates at any stage of depletion and that reservoir heterogeneity was the principal cause of reservoir losses due to rate-sensitive recovery.

In summary, the Mobil position was as follows:

(1) Reservoir heterogeneity can cause low ultimate recovery but there is no evidence that heterogeneity adversely affects rate-recovery sensitivity or that heterogeneity should be used in any MRL procedure.

(2) A PRL formula should not be used to restrict production prior to determining an MRL.

(3) A pool life index could be used to assist in determining those pools which require detailed MER studies.

(4) The Board staff's proposal should be rejected.

4.022 PanCanadian

PanCanadian Petroleum Limited is an exploration and producing company controlled by Canadian Pacific Investments Limited. It has crude oil production in Alberta of some 23,000 bbl/d. A significant portion of this production is from sandstone reservoirs in heavy-gravity crude areas.

PanCanadian stated that since each reservoir had unique characteristics of rock type, drive mechanism, fluid types, saturation conditions, and well configurations the MER or its equivalent could not be determined by a universal formula. It recommended the continuation of the present PRL formula as a surveillance device until each pool had been examined on its own merits.

PanCanadian agreed with the conclusions from the numerical simulation studies performed by Neotechnology Consultants Ltd. and by Intercomp Resource Development and Engineering Ltd., which showed that any restriction in production rate resulting in less water throughput before the economic limit was reached would reduce ultimate recovery. PanCanadian also suggested that the guidelines used to assign GPP status should be extended to include those pools for which it could be demonstrated that rate restrictions were not required.

PanCanadian intervened with respect to the Board staff's proposal and submitted it was not appropriate for heavy-gravity oil areas and was doubtful if the proposal would result in improved conservation. A tabulation of data was adduced to indicate that the proposal would have an adverse economic impact on most heavy-gravity oil pools.

In summary, the PanCanadian position was as follows:

(1) A universal MRL formula is not suitable for determining MER or equivalent rates.

(2) The present PRL formula could be retained as a surveillance device until a pool study and depletion plan are proposed.

(3) Numerical model studies of water floods indicate that any rate restriction resulting in less water throughput prior to the economic limit will reduce ultimate recovery.

(4) Recovery from most pools cannot be improved by rate restrictions.

(5) The Board staff's proposal is not appropriate for heavy-gravity oil pools.

4.023 Petrofina

Petrofina Canada Ltd. is a fully integrated oil company controlled by Petrofina S.A. Brussels, Belgium. It has Alberta crude oil production of about 10,000 bbl/d.

Petrofina was opposed to the use of a universal formula for imposing rate limitations on all reservoirs in the Province, particularly when, as it contended, the formula did not consider the recovery mechanism

involved. However, it did support the use of the existing PRL formula until such time as MER studies based on production experience and reservoir data could be completed.

Petrofina stated that the transfer of MRLs to other wells in a PSU or block may cause production to exceed the MER of an individual well. Therefore, it acknowledged there may be a need for the determination of individual-well MERs for wells that produce multiple allowables.

In its intervention to the Board staff proposal, Petrofina submitted that the proposed PRL formula appeared to be dimensionally inconsistent. It also submitted that the proposed correlation for initial PRLs may be subject to considerable error because pool rates were restricted by prorating.

In summary, Petrofina made the following points:

(1) A universal formula is not suitable for setting MRLs.

(2) The existing PRL formula can be used until an MER study is completed.

(3) Wells that produce multiple allowables may need individual-well MERs.

(4) The Board staff's proposal is deficient.

4.024 Shell

A fully integrated oil company, Shell Canada Limited is a subsidiary of the Royal Dutch/Shell Group of Companies. Its crude oil production in Alberta is chiefly from carbonate reservoirs and amounts to some 75,000 bbl/d.

Shell contended that for the majority of pools in Alberta, MRLs were neither necessary nor appropriate for the prevention of reservoir waste. It contended that the type of recovery mechanism was the most important factor in the consideration of rate sensitivity. Shell had reviewed the various recovery mechanisms by type and concluded that only in certain instances were higher production rates detrimental to overall recovery. It acknowledged that MRLs would be appropriate for pools with certain recovery mechanisms. Shell recommended that a joint Board -

Industry Group be established to determine the special situations where an MRL would be appropriate and also to formulate guidelines for setting PRLs. These PRLs would remain in force until comprehensive MER studies could be completed. Shell also contended that the majority of pools in the Province should be granted GPP status.

From its analysis of the dominant factors affecting rate sensitivity of recovery from oil reservoirs, Shell stated that reservoir heterogeneity affected the rate sensitivity of recovery only to the extent that gravity and imbibition were rate-sensitive. Shell supported the numerical simulation study by Intercomp which showed that gravity drainage was not adversely affected by high production rates and that the time necessary to achieve capillary equilibrium was small in relation to the time required to flood out a reservoir.

Shell discussed the possible effect of economic parameters on ultimate oil recovery. It stated that, since the fixed component of the operating costs would constitute the major portion of the total operating costs, the total oil production rate, as opposed to the WOR or the total fluid rate, would be the dominant factor controlling the economic limit.

Because of the diverse nature of oil reservoirs, Shell said it was unreasonable to expect a single formula to be equitable and effective in protecting all pools against reservoir waste.

Shell submitted that conservation issues and correlative rights issues should be kept separate in determining and administering MRLs. It recommended that special cases needing protection of correlative rights should be handled on an individual basis.

It was Shell's belief that the distribution of an MRL within an MRU on an acreage basis could negate the benefits of imposing an MRL. It stated that the MRL should be distributed instead, to individual production entities on the basis of the parameters that control the need for imposing the MRL.

In its intervention to the Board staff's proposal, Shell submitted that the evidence presented did not justify assignment of MRLs to all oil reservoirs. Shell disagreed with many technical and administrative

aspects of the proposal and particularly with the use of a universal MRL formula.

In summary, the following points were made by Shell:

(1) MRLs are neither necessary nor appropriate for the prevention of reservoir waste in the majority of pools in Alberta.

(2) A joint Board - Industry Group should establish guidelines for setting PRLs for the special situations or pool recovery types where MRLs are required and an MER study is not available.

(3) A single MRL formula would not be an equitable or effective method of preventing reservoir waste.

(4) Conservation and MRL matters should be kept separate from correlative rights issues.

(5) In those pools which require MRLs, the pool MRL should be distributed to the production entities on the basis of the parameters that control the need for the MRL.

(6) The Board staff's proposal should be rejected.

4.025 Texaco Canada

Texaco Canada Limited is a fully integrated oil company controlled by Texaco Inc. of New York. Its crude oil production in Alberta amounts to some 40,000 bbl/d.

The company stated that in light- and medium-gravity pools, reservoir waste was prevented by enhanced recovery approvals and application of WOR and GOR penalties to individual wells. It recommended that the present PRL formula be applied to pools producing heavy oils.

It stated that MRLs should be imposed only in cases where studies substantiated by reservoir performances indicated that reservoir waste was occurring.

In summary, Texaco Canada submitted the following:

(1) Present enhanced recovery approvals and penalty provisions are satisfactory for preventing reservoir waste in light- and medium-gravity pools.

(2) MRLs should be imposed only where there is evidence of reservoir waste.

(3) The PRL formula should be used in heavy-gravity oil pools.

4.026 Texaco Exploration

Texaco Exploration Canada Ltd. is a major exploration and producing company wholly owned by Texaco Inc. of New York. Its Alberta oil production is approximately 160,000 bbl/d, primarily from Devonian reefs.

Texaco Exploration considered the application of a single MRL or MER formula to all Alberta oil pools to be impractical due to the diverse nature of the pools. It believed that MERs should be determined on the basis of individual pool submissions and that these rates should take precedence over those determined by any generalized formula.

Texaco Exploration investigated the dependence of economic recovery on production rate for various types of reservoirs. It concluded that the premise that ultimate recovery was inversely proportional to producing rate for all reservoirs and all recovery mechanisms was too generalized to be considered correct, particularly if economic recovery were implied. It recommended that individual-well rates be limited by drawdown and distance from the free water and gas in gravity-controlled processes, by voidage replacement in horizontal water-floods, and by GOR and WOR penalties in primary or partial natural pressure-maintenance processes.

Texaco Exploration recommended that the MRL of an MRU be distributed among the wells in the MRU on the basis of well bore pay thickness and area. It believed this would encourage operators of edge wells to unitize with central-well owners, thus encouraging optimum pool development.

The following summarizes the points made by Texaco Exploration:

(1) It is impractical to apply a single MRL formula to all pools in Alberta.

(2) Rate limitations should be determined on the basis of pool studies.

(3) Individual-well rates should be limited by drawdown in gravity controlled processes, by voidage replacement in horizontal displacements,

and by GOR and WOR penalties in primary or partial pressure-maintenance processes.

(4) A better basis for distribution of MRLs to production entities would be area-thickness.

4.027 Union

Union Oil Company of Canada Limited is a fully integrated oil company controlled by Union Oil Company of California. Its crude oil production in Alberta amounts to some 18,000 bbl/d.

Union stated it was possible to produce an individual reservoir at rates so high that the ultimate recovery from the pool would be adversely affected. From its literature review, Union noted that the MER was dependent on the physical nature of the reservoir, its surroundings, its contained fluids, and its drive mechanism. Therefore, the establishment of the MER required not only reservoir fluid and rock data, but also information regarding the relationship between producing rate, pressure drop, and available reservoir energy.

Union believed that the present PRL formula could be modified to give a satisfactory rate limitation that would bear a relationship to the MER. It proposed that the PRL formula be modified to incorporate a factor which would describe the change in recovery sensitivity to producing rate with cumulative production. The modified formula would be $PRL = K(U - CP)$.

To account for the dependency of the MER on the type of producing mechanism, Union suggested that guidelines for assigning the K factor and a percentage decline be developed for each major producing mechanism. It suggested the C factor be proportional to the decline rate with values ranging from 0 to 1.0 to describe situations having no dependence, to those having direct dependence, on cumulative production.

Union concluded that PRL formula could not describe the MER of a reservoir as adequately as a comprehensive MER study. Therefore, it contended that the latter should take precedence in assigning an MRL.

Union also proposed a method of distributing the allowable within MRUs, and recommended that the present method, based on acreage, be

continued subject to the restriction of individual-well production to prevent excessive pressure drawdown.

Union spoke against adoption of the Board staff's proposal, stating that it did not consider sufficiently all the items necessary for proper MRL determination.

In summary, the Union position was as follows:

(1) It is possible to produce pools at rates sufficiently high to adversely affect ultimate recovery.

(2) The present PRL formula could be modified to provide satisfactory rate limitations until a pool MER study was available.

(3) The Board staff's proposal was deficient.

5 IDENTIFICATION OF THE MAJOR ISSUES

Although the notice of hearing simply called for methods for determining MRLs for individual well, pools or parts of pools, several other issues became apparent as the hearing progressed. The Board has identified five issues that require consideration.

5.1 The Sensitivity of Crude Oil Recovery to Production Rate

The Board staff contended that ultimate crude oil recovery would be less at high production rates because of expected deterioration in the performance of individual wells or groups of wells. It submitted that reservoir waste could result from excessive production rates at any stage of depletion and that reservoir heterogeneity was a principal factor in rate-recovery sensitivity. The Board staff stated the belief that development and operating practices were a necessary consideration in any assessment of rate-recovery sensitivity.

The industry representatives generally contended that ultimate crude oil recovery from pressure-maintained pools was not adversely affected by high production rates. Ashland, D&S, Great Plains, Home, and Imperial used numerical simulators to study the sensitivity of recovery to production rate for a wide range of conditions. The conclusions drawn by the industry representatives from these studies were that ultimate economic recovery generally improved at high production rates or was independent of production rate. They concluded that ultimate economic recovery was insensitive to individual-well production rate and that the use of selective withdrawal patterns was not detrimental to recovery.

The Board considers the determination of the sensitivity of crude oil recovery to production rate to be the principal issue to be resolved because all other issues are conditional upon finding that high production rates could adversely affect ultimate recovery.

5.2 The Need for Surveillance of Production-Rate

The Board staff contended that there was a need for a systematic and formalized surveillance procedure to assure that pool and individual-well production rates were not so high as to adversely affect ultimate recovery. It submitted that performance parameters such as gas-oil ratio and water-oil ratio must be monitored on an individual-well basis and not on the basis of averages calculated for larger production entities such as blocks, projects, and integrated schemes.

Several industry participants agreed that regular surveillance was required to ensure that ultimate recovery would not be jeopardized by high production rates. It was submitted that the factors requiring surveillance could vary with the particular pool and recovery mechanism.

The Board considers the need for and extent of surveillance to be an issue.

5.3 Methods of Surveillance

While the Board staff did not propose a specific method of surveillance, it submitted that any method of surveillance must consider individual-well performance.

Several industry participants proposed specific methods for prescreening production rates or characteristics of wells and pools to determine whether further surveillance or study was warranted.

The Board considers the methods of surveillance and surveillance criteria to be an issue.

5.4 The Need for Regulation of Production Rate

The Board staff contended that since in its opinion ultimate recovery could be affected adversely by high production rates, there was a need for systematic and formalized regulation of production rate from individual wells, pools, or portions of pools.

Most industry participants submitted that, since in their view ultimate recovery was not adversely affected by high production rates

under normal circumstances, there was generally no such need. Some did, however, acknowledge that there could be some unusual circumstances where there would be a need for regulation of production rate.

The Board considers the need for regulation of production rate from individual wells, pools, or portions of pools to be an issue.

5.5 Methods of Regulation of Production Rate

The Board staff proposed an empirical method for determining MRLs where rate-recovery sensitivity studies were not available. It also proposed a general method for regulation and administration of production rate which would be applied to the various production entities within the framework of the proration system. The general method would apply gas-oil ratio and water-oil ratio penalties and would restrict individual-well rates to a multiple of the acreage MRL allocation for a drilling spacing unit. The Board staff stated that its proposed method of regulation and administration was compatible with equity considerations and that it would provide a measure of operational flexibility such that present control-well regulations would be unnecessary.

Most industry participants took strong exception to the use of any empirical approach to determine MRLs since in their view only a few cases would require regulation of production rate and in these cases an MER or rate-recovery sensitivity study should be used to determine MRLs. They submitted that a general method for regulation of production rate was not required nor should one be introduced simply for ease of administration. It was submitted that in the few cases requiring regulation the methods of regulation and administration of production rate should recognize and vary with the specific factors contributing to the rate-recovery sensitivity.

Should a need for regulation of production rate be found, the Board considers the method of regulation of production rate to be an issue. The Board does not believe that simplicity of administration and protection of equity are issues for consideration but believes they are requirements of a method of regulation if one should be needed.

6 THE SENSITIVITY OF CRUDE OIL RECOVERY TO PRODUCTION RATE

6.1 Introduction

Certain factors are known to affect the recovery of crude oil practically attainable from a reservoir. The factors may be grouped as follows:

(a) the physical properties of the reservoir rock and reservoir fluids, and their interactions,

(b) the reservoir oil-recovery processes, and

(c) the development and operating practices in the field.

In addition, it is reasonable to assume that under some circumstances

(d) production rate

could affect oil recovery although the sensitivity of oil recovery to production rate is a matter of question.

The oil recovery process operative in the reservoir is affected by the physical properties, development and operating practices, and production rate. In turn, the production rate is affected by the physical properties, recovery process, and development and operating practices. Moreover the recovery process and the development and operating practices are subject to economic constraints - normally to the effect that total benefits or revenues from the undertaking sufficiently exceed total costs, in order to render the undertaking economically attractive. However, economic attractiveness is decidedly sensitive to production rate, which determines the cash flow. Therefore a complex set of interrelationships exists among the factors affecting crude oil recovery. These are illustrated schematically in Figure 6-1.

While there is a question of the degree to which production rate within normal ranges, may have a direct effect on recovery, there can be no doubt that through its impact on the economics of an operation, production rate influences development and operating practices which in turn, both directly and through their effect on the reservoir recovery process, affect the practically attainable recovery.

In the following sections, the Board reviews the generally understood effects of physical properties, the reservoir oil recovery

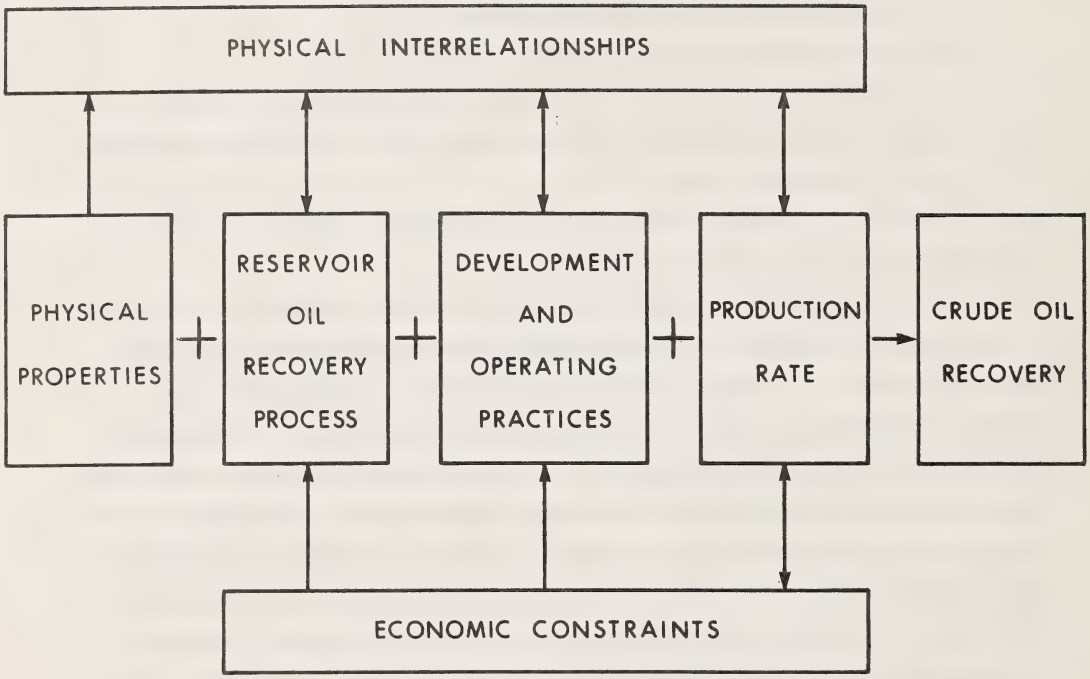

FIGURE 6-1

Schematic Diagram Illustrating the Interrelationships Among the Factors Affecting Crude Oil Recovery

processes and the development and operating practices on both the level of recovery and its sensitivity to production rate. These effects are discussed separately but the interrelations and the economic constraints must be kept in mind.

6.2 Physical Properties of Reservoir Rocks and Fluids

The recovery of crude oil from a reservoir rock is affected by the physical properties of the rock, the reservoir fluids and any injected fluids, and by interactions between the rock and fluids. The same properties and interactions may influence the sensitivity of recovery to production rate. In the following sections, the Board highlights the current state of widely accepted knowledge on these matters. Pertinent views of the participants are then presented, followed by the Board's own views on the overall significance of these physical properties regarding the sensitivity of oil recovery to production rate.

6.21 Properties of Reservoir Rocks

The two most commonly measured properties of reservoir rocks known to be important to oil recovery processes are porosity and permeability.

6.211 Porosity

The porosity - its type, variability, and level - is the single most important property of a reservoir rock. It sets an upper limit to the quantity of oil available for recovery, and affects the permeability of the rock which, in turn, influences the quantity of oil recoverable by conventional fluid displacement processes.

Porosity types are usually classed as intergranular, intercrystalline, vugular, or fractured. An individual reservoir will often exhibit more than one type of porosity. The shapes of individual pore spaces and their interconnecting channels are highly irregular, both within and between porosity types. A complete description of pore

space within a rock would include the sizes, shapes, and manner of distribution of the pores with respect to each other; the minerals lining the pores; and the microscopic roughness of these surfaces. The pore spaces may range in size from a few microns* in siltstones to several centimetres in vugular carbonates and even greater in cases of cavernous development. The porosity itself may be as low as a fraction of 1 per cent in dense rocks or as great as 35 to 40 per cent where it is highly developed. Typical ranges of pore sizes and porosities for the various porosity types are given in Table 6-1.

There is no direct way to measure the complete porosity distribution throughout a reservoir. Two indirect techniques are in common use. In one, logs and cores taken from wells are analysed and interpreted, to determine the vertical distribution of porosity at each of the well bores, and certain inferences are drawn. The inferences may be simple - that the reservoir has a certain average porosity, or more sophisticated - that the reservoir has zones of different types of porosity within which the vertically-averaged porosity varies areally in accordance with some system of interpolation between the wells. The other technique is even more inferential and involves determining from observed production and measured oil-water or oil-gas interface movement, with appropriate assumptions, what the "effective" porosity of the reservoir must be to be consistent with the observations.

While average values of porosity are normally used in reservoir engineering calculations this is recognized as a gross simplification. A typical value for an average porosity may disguise an actual range extending from less than one-tenth to more than double the average. Similarly, the average porosity level cannot describe the range in size and shape of the individual pore spaces.

It is generally accepted that oil contained in the very smallest of pore spaces, those below about one micron in average dimension, or in pore spaces poorly connected to others, is not recoverable by normal displacement processes and that, as the size of the pore spaces and porosity level increases, the recovery practically attainable increases

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* 1 micron = 10^{-4} cm

TABLE 6-1

TYPICAL RANGE OF POROSITY AND PERMEABILITY OF RESERVOIR ROCKS AS DETERMINED BY CONVENTIONAL CORE ANALYSIS

Pore Type	Pore Size Millimetres	Lower Porosity Cut-off Per cent	Maximum Porosity Per cent	Lower Permeability Cut-off Millidarcies	Maximum Permeability Millidarcies
CARBONATES					
Intergranular or Intercrystalline	0.001 - 0.5	5	35	0.1	several hundred
Vugular					
-Pinpoint	< 1	2	25	0.1	1,000
-Small/Medium	1 - 5	2	25	0.1	several thousand
-Large	5 - several hundred	2	25	0.1	very large
-Cavernous	several hundred	-	-	-	very large
Fracture	-	1	-	0.1	very large
SANDSTONES					
Intergranular					
-Silt/Fine	0.001 - 0.05	14	35	0.1	50
-Medium	0.05 - 0.1	10	35	0.1	several hundred
-Course	0.10 - 0.5	6	35	0.1	1,000
-Conglomerate	> 0.5	2	35	0.1	several thousand

rapidly at first, then levels out. The lowest porosity from which oil is practically recoverable is in the range of one or two per cent. This is recognized through the use of porosity "cut-offs" for the estimation of oil in place. Typical lower porosity cut-offs are shown in Table 6-1.

This sensitivity of oil recovery to porosity means that, with any actual reservoir rock containing a wide range of levels and perhaps even a mixture of types of porosity, the attainable recovery will be low from some portions of the rock and high from others. Because of the different ways in which porosities of the same average may be made up, the same attainable recovery cannot be expected from reservoirs of the same average porosity unless the type and range of porosity is also the same.

It is harder to generalize on the effect of porosity type and level on the sensitivity of recovery to production rate. None the less it would be expected that where the recovery is or could be affected by more than one mechanism at the pore level and where the relative significance of the different mechanisms depends upon the type or level of porosity, then the type or level of porosity could affect the sensitivity of recovery to production rate. For example, in normal immiscible displacement of oil by water in a water-wet rock, oil in the larger pores and main flow-channels is displaced by viscous forces, while that in smaller pores and side channels may be recovered only if the displacing water is imbibed into the pore spaces, discharging the oil to the main flow-channels. The displacement process may be effective at relatively high fluid velocities whereas imbibition is known to be relatively slow. Similarly, in miscible displacement, the oil in the smallest pores and side channels may be recoverable only to the extent that it is slowly discharged into the main flow stream by molecular diffusion - or a combination of molecular diffusion and eddy current dispersion. In cases like these, it seems clear in principle that the type, and range in level, of porosity could affect not only the absolute level of the attainable recovery but also the dependence of that recovery on production rate. Even an acceptance of this proposition, however, does not provide an answer to the practical question of whether, within a particular range of production rates, the attainable recovery would be affected by rate.

6.212 Permeability

In conjunction with the viscosities of the fluids, the absolute permeability and related relative permeabilities to oil, gas, and water determine the ease with which fluids may flow in the reservoir rock and directly affect the practical rates at which wells may be produced.

Permeability is highly sensitive to the type and level of porosity. For the same porosity type, a rock of double the porosity of another may have a permeability 5 to 10 times greater. Accordingly, the variability of type and level of porosity referred to in the previous section gives rise to an even greater variability in the permeability. As a result of compaction and other geological forces the permeability is often different in the horizontal and the vertical directions. Also, differential rock composition and compaction give rise to zones of varying permeability or "stratification".

The level of absolute permeability ranges from less than 0.1 millidarcies in low-quality reservoir rocks to more than 1,000 md in high-quality reservoir rocks with good porosity. The permeability variation among reservoir rocks is some 10,000-fold as compared with the 15- to 20-fold variation of porosity. Even within a single reservoir the variation in permeability of reservoir pay sections may be as much as 1,000-fold.

As with porosity there is no direct way of obtaining a complete description of the distribution of permeability within a reservoir; two indirect methods are therefore used. The first is based upon the permeability measurements of cores taken from wells and the inference drawn from these measurements. This method is the same as that described for porosity. The second method involves calculating the effective permeability immediately surrounding individual wells from measurements, at each well, of pressure and production rate over a period of time, a knowledge of the reservoir fluid properties, and certain assumptions concerning the flow behaviour. The method gives effective permeabilities applicable to the "drainage areas" of individual wells. Certain further inferences may be drawn by interpolation between wells or by special tests that measure pressure interference between wells.

With the wide range of permeability encountered in a reservoir, and even in samples from a single well bore, the use of the arithmetic mean is not usually suitable for the determination of an average or effective permeability. Warren and Price[1] have confirmed the suitability of the use of the geometric mean and state "the most probable behaviour of a heterogeneous system is that of a homogeneous system with a permeability equal to the geometric mean of the individual permeabilities".

Fluids, and particularly oil of normal viscosity (say 0.5 to 5 cp at reservoir conditions), contained in the pore spaces of reservoir rock having a permeability of the order of 0.1 md move so slowly under any normal driving force that they are considered immobile and not recoverable by fluid displacement processes. This is recognized in the use of permeability "cut-offs". Table 6-1 summarizes the lower permeability cut-off and the ranges of permeability encountered in reservoir rocks of different types.

As with porosity, the use of an average or effective permeability, which is common in reservoir engineering calculations, is a gross simplification and conceals the variation that actually exists. Calculation procedures that recognize different average permeabilities for the horizontal and vertical directions, and for different zones of the reservoir, go part way towards reflecting the actual situation but still represent rather crude approximations.

Over the range of practical well production rates and production lifetimes the recovery of oil obtainable from a reservoir is related to the average level of the permeability. The recovery is negligible for oils of normal viscosity for permeabilities of the order of 0.1 md, but increases rapidly to a permeability level of some 100 md and becomes increasingly insensitive to permeability above that level. Oil recovery is also affected by the variation of permeability within the reservoir and therefore is not necessarily the same for reservoirs of the same average permeability. Generally the more the permeability distribution is skewed towards low permeability the lower will be the recovery level that is practically attainable.

One of the ways in which the level and distribution of permeability affect oil recovery is through their effect upon the recovery process

itself (one of the several interactions illustrated in Figure 6-1). An example of this type of interaction is where the recovery of oil from the high-permeability regions of a reservoir is mainly by the gravity drainage process while that in lower-permeability regions is mainly by the less efficient solution-gas-drive process. Additionally, permeability may affect the production rate practically attainable and, through the resulting economic impact, influence the development and operating practices and their effect on recovery. All in all, permeability, like porosity, may affect the recovery of oil through its level within the range of low permeabilities, and particularly through its variability over the reservoir even at a satisfactorily high average permeability.

In principle, the sensitivity of oil recovery to production rate is affected by the level and variability of permeability in much the same way as by those of porosity. Where the recovery occurs or could occur through more than one mechanism or variations in a particular mechanism, then both low average permeabilities and the low permeability contributions to the average level of permeability could cause an adverse effect of production rate on the reservoir recovery process and on recovery. The clearest illustration of this, in a reservoir subject to both solution gas and water drive, is the increasing contribution, with increasing production rate, of recovery by solution gas drive as compared to displacement by water in low-permeability regions of a reservoir. This is another case of the kinds of interactions illustrated in Figure 6-1. As with porosity, it is not possible to generalize on the significance of the effect that could result within the practical range of production rate.

6.22 Properties of Reservoir Fluids

The physical properties of the reservoir fluids, hydrocarbon liquids and gases of varying composition, and water with varying amounts of dissolved mineral matter, influence the distribution of fluids in the reservoir and, along with the appropriate relative permeabilities, the ease with which oil may flow or be displaced in the reservoir rock. The two physical properties of these fluids of most importance to recovery

are density and viscosity. In addition, the interfacial tensions of the reservoir fluid pairs, oil-water, oil-gas, and gas-water, affect the forces required to displace oil from the pore spaces. These properties in turn depend upon the chemical composition of the reservoir fluids and the reservoir pressure and temperature.

6.221 Density and Viscosity of Reservoir Waters

Reservoir waters vary in composition from the highly saline waters common to marine sediments to relatively fresh waters in non-marine deposits and as injected in water-flood operations. For solid contents varying from a few hundred to several hundred thousand parts per million, the density of the water at atmospheric pressure and temperature varies from 62.4 to about 74 lb/cf. Pressure has little effect on the density but reservoir temperatures cause a reduction in density of about 1.5 per cent for each 50 Fahrenheit degrees above 68° F. Neither the solids content nor the reservoir pressure have much effect on the viscosity of reservoir waters but elevated reservoir temperatures cause a reduction in viscosity from 1 cp at 68° F to 0.43 cp at 150° F, 0.30 cp at 200° F, and 0.23 cp at 250° F.

The relatively small potential variation in the density of reservoir waters has little effect on the recovery processes or otherwise on the recovery of oil. The higher the water density, the greater the density contrast with oil, favouring oil recovery in vertical displacements and where coning occurs. This effect is generally small except for low-API gravity oils where the density contrast is small to begin with. Similarly, water density does not have a significant effect on the sensitivity of oil recovery to production rate except, perhaps, with the lower-API gravity oils.

High reservoir temperatures lead to low water viscosities but, since the effect on the viscosity of oil is relatively greater, the result is a reduction in the ratio of the viscosity of the oil to that of water and an improvement in the relative mobility. Consequently, the danger of recovery losses through bypassing of oil and channeling of water is normally less in high-temperature than in low-temperature reservoirs.

6.222 Density and Viscosity of Reservoir Gases

Reservoir gases may vary in composition from almost pure methane to hydrocarbon mixtures containing methane, ethane, and propane in significant quantities and heavier hydrocarbons as well. The gases may contain nitrogen, carbon dioxide, and hydrogen sulphide. Gases injected into reservoirs include air, hydrocarbons, nitrogen, and carbon dioxide. The specific gravity (air = 1.0) of these gases may vary from about 0.6 to well over 1.0, leading to densities at reservoir pressures and temperatures in the broad range of 0.5 to 20 lb/cf. The reservoir gases all have low viscosities which increase with increasing pressure but, depending on composition and pressure, gas viscosity may increase or decrease with increasing reservoir temperature. Viscosities of reservoir gases vary within the range of 0.01 to 0.04 cp.

Even though the densities of gases in the reservoir may vary several-fold they are generally much less than the density of reservoir water or oil, and the density contrast is so little affected that it is probably safe to conclude that gas density itself has little effect on either the level of oil recovery or the sensitivity of oil recovery to production rate. The situation is much the same for gas viscosity. Compared with reservoir waters and oils, reservoir gases may be considered essentially inviscid and the minor variations in gas viscosity encountered do not greatly alter the naturally unfavourable mobility ratio which exists between gas and liquids. Accordingly, gas viscosity variations have no significant effect on the level of oil recovery or the sensitivity of recovery to production rate.

6.223 Density and Viscosity of Reservoir Oils

Reservoir oils vary widely in composition and have densities ranging from about 10^{o} API to over 60^{o} API and may contain dissolved reservoir gases ranging from less than 30 to over 2,500 scf/bbl under saturation conditions. Heavy-gravity crude oils (API gravity less than 25^{o}) are often undersaturated with gas and even when saturated contain only 30 to 300 scf/bbl under the reservoir conditions in which they

occur. Their reservoir densities vary from 50 to over 60 lb/cf and their viscosities under reservoir conditions are normally high - in the range of 10 to 100 cp or more. At reservoir conditions, medium-gravity and light oils have densities generally in the range of 40 to 50 lb/cf and viscosities in the range of 0.5 to 5 cp.

The relatively high density of the heavy-gravity oils with the resultant lower-density contrast to reservoir waters has an adverse effect upon oil recovery where gravity segregation is important to the recovery process. This adverse effect could extend to the sensitivity of oil recovery to production rate. Of even greater significance is the effect of the high viscosity of heavy-gravity oils. This greatly affects the physical productivity of wells, the time of economic abandonment, the pore-to-pore recovery, and the sweep efficiency of displacement processes. The latter two effects result from the high mobility contrast with reservoir waters or gases and the consequent ease with which driving water or gas may develop channels and bypass oil. Especially when considered along with the potential variations of porosity and permeability, the high viscosities of heavy-gravity oils would tend to aggravate any adverse effect of production rate on oil recovery.

The medium-gravity oils and particularly the lighter oils show greater density contrast with reservoir water and their density variation has less effect on recovery or any sensitivity of recovery to production rate. Because of their low viscosity, the mobility ratio of medium-gravity and lighter oils with water is usually favourable and any change in pore-to-pore recovery with viscosity is normally small. On the other hand, for adverse mobilities some effect of rate on oil recovery may be expected due to viscous fingering and changes in sweep efficiency, especially in highly heterogeneous reservoirs.

6.224 Interfacial Tensions of Reservoir Fluids

The interfacial tension between reservoir oil and any contacting reservoir gas (commonly referred to as the surface tension of the oil) varies with the composition of the oil, the pressure and temperature and, to a lesser degree, with the composition of the gas. Crude oils denuded

of dissolved gases exhibit surface tensions in the range of 24 to 35 dynes/cm at atmospheric conditions and this decreases to 15 to 25 dynes/cm at elevated (reservoir) temperatures. Dissolved gases have the effect of decreasing the surface tension, often dramatically, and gas-saturated reservoir oils at reservoir conditions have surface tensions in the range of 1 to 15 dynes/cm. As the critical state is approached in the reservoir the surface tension approaches zero.

The interfacial tension between reservoir oil and reservoir water also depends upon the composition of the oil, the pressure and temperature and, to a minor extent, on the composition of the reservoir water. At atmospheric conditions the interfacial tensions for denuded crude oils range from about 10 to 35 dynes/cm. At reservoir temperatures these drop to one-half, or less, of their atmospheric values. The interfacial tension between undersaturated crude oils and water increases somewhat as the amount of dissolved gas increases. The interfacial tension of saturated crude oil decreases with increased pressure.

For the water-gas system the interfacial tension (commonly referred to as the surface tension of the water) varies with the temperature and pressure and to a lesser degree with the composition of the gas. The pressure dependence is largely due to its effect on the amount of gas dissolved in the water. The surface tension varies from about 74 dynes/cm at atmospheric conditions to as little as 30 dynes/cm at high reservoir pressure and temperature.

The interfacial tensions of reservoir fluids affect the level of oil recovery by immiscible displacement processes because of their direct effect on pore-to-pore capillary forces. These forces may contribute to recovery (e.g. water imbibition in water-wet systems) or they may be forces that must be overcome by viscous and gravity forces before oil can be displaced from small pores (e.g. in oil-wet systems). Thus, where adequate displacement forces cannot be developed and where other recovery mechanisms either are not operative or operate at a lower recovery efficiency, high levels of interfacial tension tend to cause decreased recovery. Conversely in such cases, greatly reducing or eliminating the interfacial tensions, as through the action of surface-active agents or by the use of solvents, favours increased

recovery.

Similarly, high interfacial tensions may be expected to contribute to the sensitivity of recovery to production rate where different recovery mechanisms operate at different pore sizes and where much variation in porosity and permeability occurs. To the extent that displacing forces are increased by high flow-rates, such rates could benefit recovery. However, to the extent that high rates might preclude or reduce recovery by imbibition, reduce sweep efficiency, and cause viscous fingering, their effect would be adverse.

6.225 Variation of Composition and Properties of Reservoir Oils and Gases

Variations of the composition and physical properties of both reservoir oils and gases may exist in some pools at the time of their discovery. Areal variations are common in thin, low-permeability reservoirs of large areal extent. These variations are sometimes sufficient to cause some regions to be saturated with gas and others to be undersaturated thereby affecting the recovery efficiency of the various regions. Vertical variation of fluid properties occurs in high-relief reservoirs because of the changes in the hydrostatic pressure and geothermal temperature.

When the reservoir process involves either pressure depletion or the cycling of lean gas, certain hydrocarbon components are vaporized from the reservoir oil, altering both its composition and that of the gas in contact with it. The effect is negligible or modest with heavy-gravity crude oils having low levels of gas in solution, but may be quite significant for gas-saturated medium-gravity oils and especially significant for light crude oils. The change in composition of the gas involves an increase in its content of propane and heavier hydrocarbons and these hydrocarbons are recovered to the same extent that the gas is ultimately recovered. The effect on the density and viscosity of the gas and on its interfacial tension relative to water is not normally significant and in itself has little impact on the recoverability of the oil. The change in composition of the oil is through a partial

loss of its lighter hydrocarbons. This results in an increase in its density with the result that, for the same volumetric retention in the reservoir that might otherwise occur, the actual mass recovery is reduced. This is the so-called "shrinkage" loss. Additionally the partial loss of lighter hydrocarbons results in some increase in the viscosity of the oil and its interfacial tension relative to gas, with any associated adverse effects both on the level of oil recovery and its sensitivity to production rate.

When the reservoir process involves miscible displacement (solvent-bank or condensing-gas drive) the reservoir pressure and injected fluid compositions are carefully managed so that interfacial tensions are eliminated between the displacing fluid and the reservoir oil. These processes also cause large changes in other fluid properties, including density and viscosity.

Accurate pressure-volume-temperature (PVT) data measured on carefully taken samples of the reservoir fluids are important in appraising the effect of pressure and temperature on the phase behaviour and composition of the reservoir oil and gas. The computational methods used in reservoir performance predictions should be capable of accounting for the changes in composition and physical properties that occur. The use of "black oil" or similar calculation techniques for cases where significant composition and fluid property changes can occur could mask these effects on recovery or its sensitivity to rate.

6.23 Interaction Between Reservoir Rocks and Reservoir Fluids

The interactions between reservoir rocks and fluids are evident in the wettability, capillary, and relative permeability phenomena.

6.231 Wettability

The term wettability is used in the broad sense of indicating whether or not and to what degree a fluid tends to spread out and "wet" a solid surface, displacing another fluid (liquid or gas) initially covering the surface. In a reservoir rock that is completely wetted by

a liquid, the wetting liquid will tend to occupy the smallest pore spaces and will also exist as a thin film over the surface of any pores occupied by a non-wetting fluid.

Wetting properties of reservoir fluids with respect to selected mineral surfaces may be measured by the contact angle, θ, the angle between the solid surface and the tangent of the interface between the fluid in question and the fluid displaced. (By convention, where water and either oil or gas are involved, the contact angle, θ, is reported as measured through the water phase.) The practical value of the results of contact-angle measurements depends on the degree to which the selected mineral is truly representative of the actual surface conditions of the reservoir rock.

Wettability effects are determined by the rock composition, the microscopic surface roughness, and the composition of the oil and water phases. Departure from water wetness is believed to be caused by the presence of polar- or surface-active compounds in the oil. It is also believed that the initial presence of connate water influences reservoir wettability which in turn affects the subsequent distribution of fluids.

Much of the past research and study of rock-fluid interrelationships has been based on the concept of rocks being either strongly water-wet (θ nearly 0^{o}) or strongly oil-wet (θ nearly 180^{o}), with the former predominating. It is now recognized that there may be a range and variety of types of intermediate wettability. In the most extensive survey yet reported on the wettability of individual reservoirs, Trieber, Owens and Archer[2] reported water advancing contact-angle measurements for 30 sandstone and 25 carbonate reservoirs and proposed a classification based on the magnitude of the equilibrium contact angle following advance. Using a somewhat arbitrary classification they found 15 reservoirs (13 sandstone, 2 carbonate) were water-wet ($\theta < 75^{o}$), 4 reservoirs (2 sandstone, 2 carbonate) were of intermediate wettability ($75^{o} < \theta < 105^{o}$), and 36 reservoirs (15 sandstone, 21 carbonate) were oil-wet ($105^{o} < \theta < 180^{o}$). This distribution may not be representative of reservoirs as a whole and is in distinct contrast to some views that most reservoirs are strongly water-wet.

The literature is not consistent with regard to the effects of

wettability on pore-to-pore displacement efficiency as determined by laboratory water-floods. Water-wet, intermediate-wet, oil-wet, and mixed-wet situations have all been claimed as optimum for oil recovery. In many cases, the basis for these claims rests on experimental results that cannot be readily reproduced.

The Petroleum Recovery Institute has recently performed studies[3] on systems of uniform wettability indicating that residual non-wetting-phase saturations following water-flooding are sensitive to wettability within the range termed as water-wet. Spontaneous imbibition of water was observed for contact angles of up to about 62^{o}. The residual saturations were lowest under strongly water-wet conditions ($\theta < 25^{o}$) and increased continuously by up to one-third as the contact angle increased over the range 25^{o} to 62^{o}.

The importance of wettability to recovery varies with the pore size distribution and heterogeneities of reservoir rocks. Strongly water-wet conditions promote recovery by imbibition from the smaller pores in homogeneous reservoirs which have a wide distribution of pore sizes. Moreover, strongly water-wet conditions generally result in a more favourable mobility ratio than other wettability conditions (water-wet rocks tend to be relatively less permeable to water at the residual oil saturation) and this also promotes recovery. Water-wetness is also essential for recovery by imbibition from some types of heterogeneities including tight stratified layers, isolated tight lenses, and tight matrix blocks in fractured systems. On the other hand, in systems where isolated vugs are surrounded by a granular or intercrystalline matrix, recovery of oil from the vugs requires that the surrounding matrix be oil-wet. There is some evidence[4] that oil-wet surfaces or mixed wettability conditions may promote oil recovery where there is sufficient vertical relief for gravity segregation to operate effectively.

In general, both the type (water-, intermediate- or oil-; uniform or mixed) of wettability and its degree, as measured by the contact angle, are known to affect the practically attainable oil recovery. The magnitude and direction of the effect on recovery depend upon the reservoir recovery process employed. Research on ways to alter wettability for the benefit of oil recovery is continuing.

To the extent that production rate may alter the reservoir recovery process, different conditions of wettability can affect the sensitivity of oil recovery to production rate.

6.232 Capillary Phenomena

As a result of the interfacial tensions of reservoir fluids and the small dimensions of the pore spaces, wetting fluids may be tightly held within pore spaces, and displacement by other fluids requires force and is normally incomplete. For uniformly sized pores the required displacement or "capillary" pressure is mathematically related to the interfacial tension, the contact angle of the fluids involved, and the curvature or "equivalent radius" of the pore space. For reservoir rocks having a wide range of pore shapes and sizes no such simple mathematical relationship exists, but measurements may be made on core samples with reservoir or similar fluids to obtain an experimental value for the capillary pressure as a function of the saturation of the rock with the wetting fluid.

The capillary pressure curve for a particular rock gives an overall characterization of pore-size distribution as affected by the fluid properties and the wettability of the rock-fluid system. Capillary pressure relationships are also affected by the direction of saturation change and exhibit hysteresis. The physical mechanism accounting for hysteresis is attributed[5] to localized force imbalances with intermittent but near-instantaneous fluid movements from pore to pore. Hysteresis in capillary pressure is enhanced by wettability effects due to contact-angle hysteresis, the effects of surface roughness on contact angle, and the interaction of pore geometry with contact angle.

The drainage-capillary pressure curve is that obtained when the saturation of the wetting phase is decreased. The curves for different rock-fluid combinations have some common characteristics. They generally exhibit a low initial displacement pressure when fully saturated with the wetting phase, and increasing pressure as the wetting-phase saturation is gradually decreased by displacement. Finally, as the wetting phase is displaced from the most accessible pores and isolated in the

smaller or less accessible pores, the pressure increases rapidly and asymptotically at what is referred to as the irreducible saturation by the wetting phase. Initial displacement pressures vary from near zero in highly porous and permeable rocks to several psi in fine-grained rocks. For rocks with uniform pores only a slight increase in pressure occurs over a significant saturation range while for rocks with a wide distribution of pore sizes a continuous and sometimes steep increase in pressure occurs as the wetting phase is displaced.

The imbibition-capillary pressure curve resulting from increased saturation by the wetting phase can differ considerably from the drainage curve. For wetting-phase saturations greater than the irreducible, the imbibition-capillary pressures are about one-half the drainage-capillary pressures. As imbibition proceeds, the capillary pressure continuously decreases, and as the trapped or residual saturation by the non-wetting phase is approached the pressure decreases rapidly.

The rate of imbibition at any saturation is proportional to the capillary pressure, with the negative slope of the capillary pressure curve resulting in a decreasing rate as saturation by the wetting phase increases. A positive imbibition-capillary pressure at any particular saturation by the wetting fluid means that the system will spontaneously imbibe, at a decreasing rate, to a saturation corresponding to a capillary pressure of zero. A negative pressure means that an externally applied pressure is required to increase the wetting-phase saturation above that corresponding to zero capillary pressure.

Few sets of reliable experimental capillary-pressure data have been measured with reservoir fluids in properly preserved cores. Reservoir engineering calculations are often based on capillary-pressure data from measurements made with refined fluids and extracted cores. Such data may not be representative of the in situ reservoir system.

With water-wet reservoirs, high capillary-pressure values result in relatively high rates and a high degree of imbibition with consequent favourable effect upon oil recovery. Low values, whether a result of pore geometry or of interfacial tension or wettability, mean a low degree of imbibition and low rates, with little beneficial effect on oil recovery.

An adverse sensitivity of crude oil recovery to production rate would be expected, in principle at least, in situations where the capillary forces were favourable (positive capillary pressure) but small and where the time required for imbibition is significantly greater than the time during which displaced oil could be carried to a producing well. Conversely, in principle, where capillary forces operate to retain oil in the pore spaces, as with oil-wet systems, high rates of production could improve recovery through their generation of higher viscous forces.

6.233 Relative Permeabilities

To deal with the complex situation of the flow of a fluid in a reservoir rock in which the pore spaces contain not only the fluid in question but also one and possibly two others, the concept of permeability defined by Darcy's law is extended to both effective and relative permeability. The effective permeability depends upon the absolute permeability characteristic of the reservoir rock, fluid saturations, and the saturation distribution of all fluids in the rock, the latter being affected by the physical properties of the fluids and the wettability of the system. Relative permeability is simply the ratio of the effective permeability to the absolute permeability.

The degree of wettability of the rock (by water or oil) has little effect on the relative permeabilities during the simultaneous flow of oil and gas, but has a considerable effect on the relative permeabilities during the simultaneous flow of oil and water. Where three phases may flow, the relative permeability of the wetting phase is primarily dependent upon its own saturation whereas the relative permabilities of the non-wetting phases have been shown to vary in a complex manner[6, 7]. Hysteresis effects also influence the relative permeability so that its value for any set of fluid saturations is influenced by the previous history of fluid flow.

Relative permeability - fluid saturation relationships (relative permeability curves) are normally determined by laboratory experiments, but they can also be estimated from reservoir performance in special cases. As with capillary pressure, measurements of relative permeability

should be carried out on properly preserved cores and with actual reservoir fluids. Mungan[8] has shown that measurements made with flushed cores and poorly simulated reservoir fluids may be seriously misleading. There is some evidence[9, 10, 11] that the residual-oil saturation and the saturation distribution are affected by the rate of flow of any of the fluids involved. The conventional laboratory procedures for measuring relative permeabilities use high displacement rates (to save time and eliminate capillary end-effects) and the residual saturations from these tests could be low because of the high displacement rates.

Even more than absolute permeability, relative permeability varies over the reservoir and there is no way of accurately determining and describing the variation. Average relationships between the relative permeability and saturation are used in reservoir analysis, either for the reservoir as a whole or, preferably, for each identifiable zone or stratum. These procedures, although generally useful, may be too coarse to permit, or may be based on averages to such a degree as to prevent, proper evaluation of any relative permeability effects on oil recovery or the sensitivity of recovery to production rate. Reservoir simulation by numerical models has made it possible better to account for the variations of relative permeability at least to the extent of allowing for stratification and the influence of changing fluid saturations.

The effect of relative permeability to oil on the attainable level of oil recovery is similar to that of absolute permeability discussed previously, except that it may be accentuated because of the influence of capillary-pressure hysteresis and the associated wetting phenomena. Any factor tending to reduce the relative permeability to oil below a level of the order of 1 md or so will tend to lower the attainable oil recovery.

Similarly, factors resulting in reduced relative permeability to oil increase the likelihood that oil recovery will be adversely affected by rate. Any dependence of relative permeability on rate complicates the matter in a way not yet understood.

6.24 Views of the Participants

Quantitative evaluation of the specific effects that physical properties have on the sensitivity of oil recovery to production rate were made by only a few participants but qualitative assessments were made by several of them.

Board Staff

The Board staff contended that reservoir heterogeneity was a principal cause of losses due to the rate sensitivity of recovery. It contended that wide variation of physical properties lead to adverse performance which adversely affected the sensitivity of recovery to production rate. The coefficient of variation for the permeability frequency distribution was proposed as a convenient quantitative measure of heterogeneity that could be used in PRL formulae and some types of rate-recovery sensitivity calculations.

The Board staff expressed the opinion that reservoir simulation studies which considered variable properties, including variable capillary pressure and relative permeability relationships, were more likely to detect rate-recovery sensitivity. It questioned the conclusions to be drawn from sensitivity analyses, where capillary pressure relationships were arbitrarily changed without any change to relative permeabilities. It also noted the almost complete lack of definitive data on rock wettability for Albertan reservoirs and concluded that many of the capillary pressure and relative permeability relationships now in use could be unrepresentative and yield erroneous results even when used in the most sophisticated mathematical simulation models. It suggested that water-oil relative permeabilities may be rate-sensitive themselves because of complex wetting phenomena.

Alminex

Alminex stated that light-, medium-, and heavy-gravity crude oil reservoirs should be subject to the same conservation principles and controls. It expressed the opinion that pressure maintenance by waterflood was generally more efficient at high rates because only a few reservoirs had wettability characteristics in the range where imbibition was significant.

Ashland

Ashland submitted that the coefficient of variation was not a satisfactory parameter to measure reservoir heterogeneity because it did not account for the spatial position of the heterogeneity within the reservoir.

The Neotec study included a comprehensive review of the properties affecting horizontal water-floods and, based on a literature review and its model studies, the following conclusions were drawn:

(1) Mobility ratio has a large influence on areal and vertical sweep efficiencies, the rate of imbibition, and economic ultimate oil recovery.

(2) Reservoir heterogeneity should be represented by procedures that account for spatial position.

(3) There are no standard procedures which will assure the laboratory-measured relative permeability and capillary pressure relationships are representative of conditions existing in the reservoir.

(4) Imbibition will take place in a reasonable time in a water-wet reservoir and not at all in an oil-wet reservoir.

(5) Gravity effects in a horizontal water-flood are undesirable. These tend to be reduced by higher flow-rates but this approach is impractical in most cases.

(6) Frontal instabilities in water-floods are not yet clearly understood.

In its mathematical model studies of horizontal water-flooding, Neotec found that increased stratification and increased rates both tended to decrease the recovery at breakthrough. For any specified stratification, however, this adverse breakthrough performance did not prejudice ultimate recovery, since in all cases model predictions indicated improved recovery with increased rates. The spatial position of stratified layers was shown to affect the level of recovery but spatial position did not alter the general conclusion that increased rates resulted in increased ultimate recovery for the types and combinations of heterogeneities modelled. Model studies indicated that increased oil viscosity resulted in adverse performance and decreased ultimate recovery,

but did not indicate for the two oil viscosities investigated (2.5 and 25 cp), any need for a change in the overall conclusion that increased rates resulted in increased ultimate recovery. In the homogeneous case, ultimate recovery was slightly reduced by increased capillary pressure, but improved with increased rate. In layered systems, increased capillary pressure was shown to improve or decrease ultimate recovery depending on the relative position of the more permeable layers, but ultimate recovery improved with increased rate for the two capillary-pressure relationships studied.

D&S

D&S used a mathematical model to study primary depletion from a two-layer stratified reservoir. The model runs indicated that ultimate recovery was sensitive to the level of permeability and the spatial position of the more permeable layer. The runs also indicated that oil recovery from this type of reservoir (solution gas drive modified by gravity segregation) was improved by increased production rate.

Great Plains

The Intercomp study formed the quantitative basis for Great Plains' conclusions concerning the effects of physical properties on rate-recovery sensitivity. Great Plains stated that proper values of relative permeability were those measured in a homogeneous core at rates high enough to minimize or eliminate capillary pressures and end-effects. Intercomp also stated that relative permeability was not a function of rate, and made reference to several studies[12, 13, 14] and the recent work of J. D. Huppler[15]. The latter studied the effects of core heterogeneities on water-oil relative permeabilities and found that, if core heterogeneities were well distributed, rate had a small effect, but as heterogeneities became channel-like, their influence on relative permeability was more pronounced. Multiple-rate permeability-testing of specimens provided a means of assessing whether significant heterogeneities were present. Intercomp concluded that

> "if a core sample exhibits a rate-dependent relative permeability, it is either due to improper scaling, internal capillary forces, or heterogeneities."

Its simulation runs used relative permeabilities that were assumed to be from homogeneous core samples and which would not vary with laboratory

displacement rates. It acknowledged that research in the area of complex wettability phenomena was not complete.

Intercomp studied the effects of heterogeneity (some model runs were made for stratified layers one foot thick), level of capillary pressure, type of rock wettability, variable viscosities, and type of relative permeability in both horizontal and vertical pressure-maintained water-floods. Their overall conclusions were, in general, the same as those of Neotec, i.e. physical properties affect the rates attainable, the performance characteristics, and the ultimate recovery, but for any fixed set of physical properties model studies indicated no adverse affect of increased rate on ultimate economic recovery.

Gulf

Gulf submitted that MRLs should not be set for pools with oil viscosities in excess of 10 cp because economic considerations in these pools overshadowed any possible rate-recovery sensitivity effects. Based on some generalized criteria for estimating rock wettability, Gulf submitted that possibly all the Devonian pools in Alberta have intermediate wettability and therefore would not exhibit any rate-recovery sensitivity because of imbibition. Gulf considered that permeability stratification could affect rate-recovery sensitivity in horizontal displacement processes if the permeability distribution had a coefficient of variation greater than 0.75.

Home

Home presented a qualitative discussion of the effects of various physical properties on recovery efficiency. Home stated that mobility ratio and relative permeability were important to oil recovery although not rate-sensitive. Capillary imbibition was considered to be important to recovery efficiency in the water-flooding of strongly water-wet rocks with good vertical communication, but the process was stated to be relatively insensitive to rate. Reservoir performance in thick reservoirs with good vertical continuity was stated to be rate-sensitive because of gravity forces, but the effect could be favourable or unfavourable depending on other factors. Reservoir pressure was considered important to recovery because of its effect on fluid properties, well productivity, and the economic limit, and was rate-sensitive insofar as

it was affected by voidage replacement.

Home performed cross-sectional model studies for pressure maintained water-flooding of two types of reef facies. For the reef-rim facies runs, increased production rates caused earlier water breakthrough, but ultimate recovery was relatively insensitive to rate. Increased rates in the reef-lagoonal facies had little effect on breakthrough recovery but they significantly improved ultimate recovery.

Hudson's Bay

Hudson's Bay stated that the setting of MRLs for pools producing heavy crude oil was undesirable because of the marginal economics.

Husky

Husky stated that heavy-gravity crude oil (less than 20^{o} API) should be considered separately from lighter crude. It contended that enhanced recovery techniques suitable for heavy oil may be independent of primary depletion and that there may be an advantage to having the natural reservoir energy completely depleted before enhanced recovery operations were started.

Imperial

Imperial evaluated the effect of reservoir properties on oil recovery and its sensitivity to rate by making multiple simulation runs for different properties. Its findings were as follows:

(1) A reduction of horizontal to vertical permeability in a coning model of a homogeneous Leduc reservoir resulted in earlier breakthrough and increased water production. Although the effect of increased rate was to cause higher WORs, ultimate recovery to the economic limit was improved. This was attributed to better flushing from cycling large volumes of water.

(2) The effect of introducing tight lenses in an otherwise homogeneous matrix of a coning model was to reduce recovery and increase water production. Recovery from the tight lenses was less than from the rest of the system and varied with lens properties, position, and the fluid production rate. In each case the total recovery was improved at high rates because of better flushing of the bulk of the reservoir.

(3) Changing from water-wet to oil-wet conditions in a coning

model of a homogeneous reservoir resulted in less favourable WOR performance. Water breakthrough occurred earlier and was more sensitive to production rate in the oil-wet runs. Despite the adverse rate-performance relationships, increased rates were predicted to improve recovery to the economic limit.

(4) In the cross-sectional model studies the effect of layer thickness, capillary forces, and gravity forces were selectively evaluated at multiple production rates. Water-flood recovery from this model was found to be relatively insensitive to any of these factors. It was concluded that an unusual set of reservoir characteristics would be required to obtain improved recovery at lower rates.

(5) A model of the Mattax and Kyte[16] imbibition system (9-ft cube with permeability of 1.9 md, porosity of 9.1 per cent, oil viscosity of 1.8 cp, water viscosity of 0.6 cp, and free oil-water contact advanced at 1 inch/day) was used to check the validity of the capillary pressure and relative permeability functions used in Imperial's model studies. A reasonable comparison was noted and it was concluded that the relationships were valid and that imbibition in low permeability rocks could be completed within practical field lifetimes.

Mobil

Mobil said there was no evidence to show that reservoir heterogeneity caused or aggravated rate-recovery sensitivity.

Shell

Shell stated the belief that reservoir heterogeneity may cause rate sensitivity in only limited cases. It referred to Intercomp's model studies which showed that the rate of imbibition was fast compared to the life of a water-flood.

Texaco Exploration

Texaco Exploration reviewed the manner in which physical properties affected the classical fractional flow and frontal advance equations.

6.25 Views of the Board

The Board's broad understanding of the manner in which physical properties can affect the recovery of crude oil and the sensitivity of that recovery to production rate is presented in Sections 6.1, 6.21, 6.22 and 6.23. Its conclusions based on that understanding and the evidence presented at the hearing are given in the following.

Reservoir Rock Properties

The Board recognizes that reservoir rocks are generally heterogeneous with wide variations in the type and level of porosity and consequently in the permeability. It agrees with the general view of most participants that increased rock heterogeneity tends to reduce overall displacement efficiency and ultimate oil recovery. The contention of the Board staff that heterogeneity is the principal cause of an adverse effect of production rate on oil recovery, although intuitively appealing, is considered by the Board unproved. The quantitative evidence from numerical simulation models of pressure maintained waterfloods showed that for a wide range of specified reservoir heterogeneity increased production rate caused a deterioration in performance parameters (recovery to breakthrough, instantaneous and cumulative WOR), but that if the model prediction was continued to the economic limit ultimate recovery was not adversely affected. The Board accepts the results for the specified and idealized cases of heterogeneity but is not prepared to extrapolate them to the random type of heterogeneity encountered in some reservoirs.

While the Board agrees with Ashland, Great Plains, Imperial, and others who concluded that it is necessary to consider the spatial position of stratified zones or tight lenses to determine adequately the effects of heterogeneity on recovery and the sensitivity of recovery to production rate, it believes that the potentially wide range in type and level of porosity and range of permeability concealed within average values dictates a need for caution. This wide range also suggests that the degree to which recovery may be affected by production rate cannot be completely answered by any reservoir analysis that does not fully account for these variations. Accordingly, the Board does not accept

that the full effects of variation in reservoir rock properties on recovery, and especially on the sensitivity of recovery to production rate, can be evaluated from the type of data available, notwithstanding the sophistication of the analysis. For reservoirs showing significant heterogeneity in rock properties, the Board believes it appropriate to assume that increasing the production rate could decrease the final recovery and that caution should be exercised in authorizing rates above those generally accepted as safe.

Reservoir Fluid Properties

The Board recognizes that the properties of the reservoir fluids may normally be altered only by some enhanced recovery techniques but believes that where certain fluid properties (e.g. high oil viscosity) are known to result in low oil recoveries it would be wise to be cautious in accepting that oil recovery is independent of production rate. For light- and medium-gravity oils in a pressure depletion environment, or in contact with cycled lean gas, composition changes may result in property changes which have an adverse effect on recovery and its sensitivity to production rate. The so-called "black oil" method of reservoir analysis is not adequate in these cases.

The Board agrees with Ashland, Great Plains, Home, and others that, because of its direct effect on mobility ratio, increased oil viscosity has an unfavourable effect on areal and vertical sweep efficiencies and the rate of water imbibition. These all tend to decrease ultimate oil recovery and increase the probability that recovery will be sensitive to production rate.

The Board also agrees with Gulf, Husky, Hudson's Bay, and others who stated that reservoirs containing heavy-gravity crude oil require "special consideration". This is warranted primarily because of the high viscosity of these oils.

Reservoir Rock-Fluid Properties

The Board agrees with Ashland's conclusion that there are no standard procedures to ensure that the relative permeability and capillary pressure relationships used in calculations are truly representative of reservoir conditions. The general approach used by Neotec, Intercomp, and Imperial to evaluate the effect of wettability and

capillary behaviour was to change selectively the capillary pressure relationships and rerun the reservoir simulation calculation. Their conclusion was that, although wettability affected both the oil recovery and the overall reservoir performance, wettability had no adverse effect on the sensitivity of oil recovery to production rate. The Board believes there are some uncertainties affecting that conclusion. It shares some of its staff's concern over the present state of knowledge of these phenomena and questions the validity of using somewhat arbitrary capillary pressure and relative permeability relationships in numerical models to perform some types of rate-recovery sensitivity analysis.

The Board accepts that trapped or residual oil saturation within individual pores depends upon the instantaneous balance among the capillary, viscous, and gravity forces at the time of entrapment. It notes that there seems to be no clear understanding of the effects of wettability on the pore-to-pore displacement efficiency. In fact the main concern with residual oil saturations determined by laboratory flooding tests appears to be that the reservoir wettability is not correctly represented. In some cases, and in some sections of rock, residual oil saturations determined by in situ methods have been found markedly different from those given by laboratory flooding tests. Another area of uncertainty relates to the redistribtuion of oil resulting from countercurrent imbibition after a flood front has passed through a given zone. In reservoir simulation, it is normally assumed that the relative permeability curve is reversible with respect to change in oil saturation so that any oil entering the once swept zone will be produced. The Board believes that laboratory demonstration of the correctness of this assumption is needed.

6.3 Reservoir Oil Recovery Processes

Recovery of oil from reservoir rocks may occur through any one or often a combination of three basic processes - expansion of reservoir rocks and fluids due to pressure reduction, displacement by an immiscible fluid, and displacement by a miscible fluid. In addition, effects of gravity segregation, and capillary imbibition may affect the recovery process either favourably or unfavourably. A broad classification of the different recovery processes is shown in Table 6-2. Processes 1(c) and 1(d) are respectively the same in principle as processes 2(b) and 2(c) when they occur with pressure reduction.

Typical efficiency levels for pore-to-pore displacement and overall pool recovery are also shown in Table 6-2. The former are strongly affected by fluid properties (particularly the oil viscosity) and inter-relationships between rock and fluids (wettability, capillary pressure, and relative permeability). The overall pool recovery efficiency may be expressed as the product of the pore-to-pore oil displacement efficiency and the volumetric sweep efficiency. The resultant wide range in overall pool recoveries is caused by the effects of reservoir conditions on the efficiencies of pore-to-pore displacement and volumetric sweep. For this purpose unfavourable reservoir conditions include:

(a) low porosity and permeability,
(b) highly-variable porosity and permeability,
(c) high oil viscosity, and in some cases
(d) thin reservoir pay section.

6.31 Response Time - Transient or Unsteady State Effects

While it is sometimes convenient to visualize reservoirs as responding immediately to changes in rates of production of oil, gas, or water or to rates of fluid injection, such a simplification may be misleading. The pressures in the various regions of a reservoir do not respond uniformly or instantaneously to changes in production or injection. The delay of action or transient effect depends upon the properties of the reservoir

TABLE 6-2

BROAD CLASSIFICATION OF RESERVOIR OIL RECOVERY PROCESSES SHOWING TYPICAL LEVELS OF PORE-TO-PORE DISPLACEMENT EFFICIENCY AND OVERALL POOL RECOVERY EFFICIENCY

Reservoir Oil Recovery Processes	Pore-to-Pore Displacement Efficiency Per cent of Local Oil in Place	Overall Pool Recovery Efficiency Per Cent of Pool Oil in Place
1. Naturally-occurring expansion drives with pressure reduction		
(a) simple expansion drive	1-5	1-5
(b) solution gas drive	5-50	1-30
(c) gas cap drive	10-75	5-65
(d) water drive	25-75	20-70
(e) combination drive	10-75	5-65
2. Externally-caused displacement by an immiscible fluid with or without pressure reduction		
(a) horizontal	25-75	5-50
(b) vertical downward	25-75	10-70
(c) vertical upward	25-75	10-70
3. Externally-caused displacement by a miscible fluid with or without pressure reduction		
(a) horizontal	95-100	20-65
(b) vertical downward	95-100	70-90

In addition, all processes may be affected favourably or unfavourably by gravity segregation and capillary imbibition.

rock and its contained fluids, and the distances involved. The diffusivity constant of a rock-fluid system, $k/(\phi\mu c)$,

where: k = average permeability, md,
ϕ = average porosity, fraction,
μ = fluid viscosity, cp,
c = fluid compressibility, vol/vol/psi.

is a measure of the rate at which the system will adjust to a disturbance imposed on it. For systems of comparable size, geometry and boundary conditions, response is most rapid when the diffusivity constant is large. For the same reservoir rock the response time is inversely proportioned to the product of the viscosity-compressibility product of the fluid that is flowing. The viscosity-compressibility product for water ranges from about 1×10^{-6} to 5×10^{-6} cp/psi whereas that of light-gravity oil from about 10×10^{-6} to 50×10^{-6} cp/psi. Accordingly, a reservoir filled with oil could take twice and up to 50 times as long to respond to a disturbance as the same reservoir filled with water.

Reservoir recovery processes involve the action of a driving force for fluid movement operating against a resistance to that movement. The driving force is one or a combination of a gradient in system pressure, the gravitational force and the gradient in capillary pressure. The resistance to fluid motion, when laminar in nature, is proportional to the velocity and the viscosity of the fluid and inversely to the effective permeability of the reservoir to the fluid; when turbulence is present the resistance includes an inertial term incorporating the fluid density and the square of the velocity.

Where both the driving force and the resistance remain more or less constant over significant periods of time, the rate of fluid motion is also more or less constant and the system is said to be in a steady state. Alternately where either or both the driving force of the resistance varies significantly with time the rate of fluid motion will also vary and the system is in an unsteady or transient state.

In many situations upon the initiation of a change or disturbance, there is an initial transient period followed by one which is at least approximately steady state. Systems characterized by a large diffusivity constant usually have initial transient periods of only short duration and for practical purposes often may be treated as though in a steady state. Where highly compressible fluids are involved and particularly where the rock permeability is low the transient period may be very long and a proper analysis of the situation requires that the details of the transient or unsteady state effects be considered.

It is difficult to generalize on the effects of delayed response - or transient behaviour - on either the level of oil recovery or its sensitivity to production rate other than to note that reservoir systems exhibiting slow response with respect to increases in production rate correspondingly show slow response to decreases in rate or to other changes in the system. For this reason the analysis of reservoirs containing low permeability regions is considerably more complex and generally less certain.

The following discussion on the effect of the reservoir recovery process on recovery and its sensitivity to production rate is presented from a steady state viewpoint. The modifying effects of the transient behaviour following changes of production or injection rates, which can be significant for systems characterized by small diffusivity constants should be kept in mind.

6.32 Naturally-Occurring Expansion Drives

The expansion of reservoir rock, water, crude oil, and natural gas with pressure depletion is the basic mechanism for the recovery of crude oil by the naturally-occurring expansion drives shown in Table 6-2. Although all such drives are caused by simple rock and fluid expansion, their pore-to-pore displacement and volumetric sweep efficiencies are different. Matters are further complicated because these drives often act in combination and each is affected to a different degree by gravity, capillary and viscous forces. In the following subsection the Board reviews the state of widely accepted knowledge of naturally occurring expansion drives.

6.321 Simple Expansion Drive

The simple expansion of reservoir rocks and liquids can contribute significantly to overall pool recovery in reservoirs where the crude oil is highly undersaturated. Although these drives are usually short-lived (i.e. reservoir pressure declines rapidly) they have a high volumetric conformance (sweep efficiency).

Because of the relatively low compressibility of these systems (low compared to those having a gas saturation), pressure transients travel very quickly and the flow behaviour approximates that of an idealized incompressible system. Also, the expansion and compression of reservoir rocks and liquids is generally considered to be a reversible process and there is no reason for crude-oil recovery by simple expansion drive to be affected by production rate.

6.322 Solution Gas Drive

The development of a dispersed, immobile gas saturation is often the first and most efficient phase of a solution gas drive. This immobile gas saturation is generally higher for coarse-grained rocks than for fine-grained rocks. In some cases, two-phase flow of gas and oil starts immediately upon reaching the bubble point and recovery is not improved since an immobile gas saturation does not develop. In other cases, oil recovery can be improved by the development of an immobile gas saturation, particularly if the depletion plan is to maintain pool pressure by fluid injection after a dispersed gas saturation has been established. This practice makes full use of the compressive energy of the gas, but for optimum results it requires a near-uniform pressure distribution throughout the pool. The volumetric conformance and the contribution of a dispersed gas saturation to overall pool recovery could be affected by pool or individual well production rates if these rates caused wide variations in pool pressure.

After the development of any immobile gas saturation, the next phase of a solution gas drive is coalescence of expanding gas bubbles, thereby providing a network of gas-saturated pores and an incipient

permeability to gas. As free gas starts to flow in the reservoir, the displacement efficiency of the expanding gas diminishes rapidly and the producing GOR increases. The oil productivity decreases as the depletion process proceeds because of declining pressure, decreasing oil permeability, and increasing oil viscosity.

It is sometimes assumed that the greater the reservoir energy (i.e. the more gas dissolved in the crude oil) the greater will be the recovery. In practice this is seldom the case because with increased gas in solution there is increased oil shrinkage. Greater shrinkage results in larger gas saturations which in turn causes a higher producing GOR, decreased utilization of reservoir energy, and reduced recovery. The efficiency of solution gas drive is also greatly dependent on the drainage relative permeability relationships for simultaneous flow of oil and gas. Accordingly, for each reservoir rock-fluid combination there is an optimum quantity of dissolved gas for which the overall recovery by solution gas drive is the greatest.

The solution gas drive mechanism is of particular interest in the study and evaluation of the sensitivity of recovery to production rate since, if reservoir pressure is not maintained, it may supplant other more efficient drive mechanisms. The effect of production rate on ultimate recovery where the recovery process is dominated by solution gas drive has been extensively studied on both an experimental and a theoretical basis. The general conclusion is that, for a homogeneous reservoir containing crude oil of normal viscosity, production rate has only a minor effect on ultimate recovery. The more general case of the effect of individual-well production rate on ultimate recovery from heterogeneous multiple-well pools has not been as thoroughly studied, nor can as generalized a conclusion be drawn because of the greater likelihood for the development of gravity segregation or other drives.

6.323 Gas Cap Drive

In reservoirs with sufficient vertical relief the initial presence of, or subsequent development of, a gas cap provides a source of reservoir energy which tends to maintain reservoir pressure and increase

ultimate recovery. When a gas cap is present initially, the degree of pressure support is closely related to the relative sizes of the gas cap and oil zone and to the pool depletion plan (e.g. whether produced gas is to be re-injected). If the gas cap is large relative to the oil zone, little pressure depletion occurs and the pore-to-pore displacement efficiency is comparatively good, even if there is little counterflow of gas and oil. In this case the overall recovery is largely determined by the pore-to-pore displacement efficiency of the expanding gas cap and the volume of oil zone that can be displaced prior to significant breakthrough and production of gas-cap gas. However, in cases where an initial gas cap is small or a secondary gas cap develops, significant pressure depletion occurs and the overall recovery is greatly affected by the vertical permeability and the extent to which gas and oil are able to counterflow and segregate. In all cases the overall recovery with counterflow is improved because of increased pore-to-pore efficiency.

Recovery from gas-cap drives is affected by production rate to the extent that increased rate causes production of gas-cap gas and liberated gas that otherwise would be retained in the reservoir to maintain pressure and displace more oil. No generalizations of the efffects of rate on recovery are possible without considering the effects of reservoir heterogeneity and the impact of various operating practices such as concurrent depletion, re-injection of produced gas, selective well operation, etc.

6.324 Water Drive

The pressure performance of an oil reservoir subject to a water drive depends on the balance between the voidage created by withdrawals (production rate) and the rate of water influx from the aquifer. Essentially full pressure maintenance may occur if the aquifer has good permeability and is being replenished or is very large relative to the oil reservoir. The more common situation, however, is a partial water drive where the pool pressure varies with the pool production rate. Although water is only slightly compressible, unsteady state or transient

aquifer behaviour often develops because of the ever increasing and comparatively large distances from which compressive energy is drawn. Generalized solutions for transient-flow behaviour are available for several idealized aquifers having uniform rock and fluid properties and simple geometrical shapes. The unsteady state behaviour and degree of pressure support from aquifers with heterogeneous rock properties and irregular geometries can be determined by numerical models.

The displacement of oil by encroaching water is a gravity dominated process in the bulk of the reservoir and the pore-to-pore displacement efficiency is largely determined by the pore size distribution, wettability, oil and water viscosities, and other physical properties discussed in Section 6.2. Normally, only small variations in pore-to-pore displacement efficiency would be expected from changes in the rate of interface advance caused by variations in pool production rate. In those special cases where imbibition is an important part of the recovery process (e.g. reservoirs containing tight lenses or dense matrix-fracture systems) changes in rate of interface advance could affect the pore-to-pore displacement efficiency.

The overall recovery efficiency for a pool subject to a water drive is determined by the degree that reservoir pressure is maintained, the pore-to-pore displacement efficiency of encroaching water, and the portion of the reservoir flushed with water (volumetric sweep). High pool production rates can cause reduced pressure and the development of less efficient drive mechanisms. High individual-well rates can distort oil-water interfaces and reduce the volumetric sweep efficiency (e.g. water coning in vertical systems or water tongues in inclined systems). Although high individual well rates can reduce the volumetric sweep efficiency, they can make it economical to flush more water through the reservoir thereby improving the pore-to-pore displacement efficiency.

6.325 Combination Drive

Most pools are subject to a combination of the naturally-occuring expansion drives in their early stages of development and depletion. For example, a simple expansion drive is always present whenever there

is pressure depletion, but its contribution to overall recovery is usually small compared to the recovery caused by displacing gas or water. A combination gas-cap drive and solution gas drive may operate over a wide range of pool production rates in a closed reservoir (one not connected to an aquifer). Combination water drive and solution gas drive, or combination water drive, solution gas drive, and gas-cap drive can develop in pools connected to an aquifer. The efficiency of all drives can be significantly affected by gravity segregation.

Reservoir engineering calculations of performance and recovery for naturally-occuring expansion drives range from tank-type material balances and classical unsteady-state solution for water influx, both of which assume uniform properties, pressure, and saturation to multi-dimensional numerical simulations where the variation of properties, pressure, and saturation in time and space is accounted for. It is often useful and informative to express the results of these studies in terms of the fraction each of the drive mechanisms (solution gas drive, gas cap, and water drive) are contributing to recovery through the use of drive indices. For example, in the early life of a pool the solution gas drive index may be 0.4, the gas-cap drive 0.2 and the water drive index 0.4. When the same pool is close to its economic limit the drive indices could have changed to 0.1, 0.1, and 0.8 respectively. Since the pore-to-pore displacement efficiencies of the various drives may be different and the portions or volumes of the reservoir which can be successfully swept by each drive are different, the overall pool recovery will also be different for different combinations of them. The contribution to the total recovery from the different drives often depends upon the production rate as does the volumetric sweep efficiency of the various drives. Where this does occur, it is clear that the level of recovery will be sensitive to production rate and that appropriate variations of both pool and individual well rates are required to achieve maximum recovery.

6.326 Views of the Participants

Board Staff

The Board staff agreed with the majority that the simple expansion and solution gas drive mechanisms were not intrinsically rate-sensitive. It expressed the opinion, however, that in multi-well pools these were seldom the only drive mechanisms and that sensitivity of recovery to production rate could develop whenever there were competing drive mechanisms. The Board staff contended that GOR performance of individual wells indicates how effectively reservoir energy is utilized. The position of the Board staff was that if individual well GORs varied widely, those wells with high GORs should be restricted to conserve reservoir energy, and it considered the present GOR penalty schedules effective in this regard. The Board staff stated the belief that its position was supported by the findings of Cook and Fulton[17] in a recent study of the effect of production rate, completion interval, and vertical permeability on recovery and performance of solution gas drive as modified by gravity segregation.

D&S

D&S used a three-phase radial coning model to study the effect of individual well production rate on recovery from a two-layered reservoir depleted by solution gas drive modified by gravity segregation. On the basis of this particular study and other knowledge, D&S concluded that when a more permeable reservoir layer lay beneath a less permeable one, oil recovery was good and essentially insensitive to the production rate (a fixed reservoir voidage rate was used in the model study). On the other hand, when a more permeable reservoir layer lay above a less permeable one, oil recovery was comparatively low and recovery was increased by higher production rates. In the latter case, at any stage of depletion less gas was produced at the higher production rates. D&S concluded that rate restrictions were not required for conservation reasons where the recovery was by solution gas drive modified by gravity segregation, since the effect of increased reservoir withdrawal rate was at worst negligible and in some cases beneficial to recovery.

Gulf

Gulf gave no specific views on the effect of production rate on recovery from pools subject to naturally-occuring expansion drives. However, it concluded from past submissions and its operating experience that production rate affected ultimate recovery only in specific pools subject to particular recovery mechanisms and that production rate in such cases should be based on the subsisting pool energy level. It stated that the best measure of remaining reservoir energy was given by periodic pressure surveys.

Husky

Husky contended that in heavy-gravity oil pools producing by solution gas drive increased production rate did not have an adverse effect, and could have a beneficial effect, on ultimate recovery. Husky stated that its experience with over 1,200 wells in the Lloydminster area had been that specialized development and operating practices (e.g. the type of bottom-hole pumping equipment installed) permit significantly increased production rates without adversely affecting ultimate recovery. Production performance plots were presented for four wells producing by solution gas drive where the installation of special heavy crude oil pumps increased both the oil production rate and the ultimate recovery. Performance plots were also presented for ten wells from Saskatchewan heavy-crude-oil pools which had produced under solution gas drive at capacity rates of 50 - 100 bbl/d with no apparent adverse effect on recovery.

Husky cited three references[18, 19, 20] to support its contention that recovery by solution gas drive was not adversely affected by high production rates.

Imperial

Imperial agreed that the only means of maintaining efficient recovery under natural recovery mechanisms (combination drives) was to exercise rate control to achieve the benefits of the most efficient natural drive mechanism. It referred to Buckley's[21] formulation of the original MER concept:

> "Excessive rates of withdrawals leads to rapid decline of reservoir pressure, to release of dissolved

> gas, to irregularity of the boundary between the invaded and non-invaded sections of the reservoir, to dissipation of gas and water, to trapping and by-passing of oil, and, in extreme cases, to complete loss of demarcation between the invaded and non-invaded parts of the reservoir, with dominance of the entire recovery by inefficient dissolved gas drive. Each of these effects of excessive withdrawal rates reduces the ultimate recovery of oil". Also, "for each reservoir there is for the chosen dominant mechanism a maximum rate of production that will permit reasonable fulfilment of the basic requirements for efficient recovery".

Imperial pointed out, however, that since Buckley's formulation, pressure maintenance has become a practical alternative to primary depletion with the result that production rates can be varied over a broad range while maintaining recovery efficiency.

Shell

Shell cited six references[18, 19, 20, 22, 23, 24] from the literature which concluded that recovery by solution gas drive was either insensitive to production rate or improved by increased production rates. It stated that the difference in the conclusions depended upon whether gravity and capillary effects were neglected or included.

Others

Hudson's Bay, Shell, Union and others referred to the prevention of waste of natural reservoir energy by excessive well or pool rates, particularly during initial pool development. The primary concern was for the control of early production rates while the potential of naturally occurring expansion drives was being assessed.

6.327 Views of the Board

While the Board agrees that pressure maintenance has often become a practical alternative to naturally occuring expansion drives, such drives are none the less important since several major Alberta pools are being depleted solely under natural drive mechanisms as are all new discoveries. The Board's views are summarized in the following.

General

1. The portion of a pool's recovery contributed by simple expansion drive is not affected by production rate.

2. Subject to 1, naturally-occurring expansion drives should be considered to be potentially rate-sensitive, particularly where a combination drive develops.

Effect of Individual Well Production Rate on Recovery

3. In any situation recovery could be improved if, at a lower rate, the producing GOR could be reduced and a regional or localized solution gas drive wholly or partially supplanted by other more efficient drives.

4. In a homogeneous or randomly heterogeneous reservoir with favourable rock and fluid properties* and subject to 3, individual well rates in multi-well pools can be varied over a wide range without significantly affecting the pool recovery.

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*Homogeneous reservoir rock means - relatively uniform level of porosity and permeability both horizontally and vertically throughout a reservoir; extremes of high and low permeability are normally not present; some of the Viking and Blairmore sands are examples.

Randomly heterogeneous reservoir rock means - relatively large variation of porosity and permeability both horizontally and vertically throughout a reservoir, the variation is irregular on a relatively small scale, but when viewed on a larger scale (such as intervals of feet or more in a wellbore, or among different wells) there is macro uniformity; some D-3 reservoirs are examples.

Stratified reservoir rock means - relatively large variation of porosity and permeability throughout a reservoir, the variation is ordered and exists over a larger scale (such as intervals of feet or more in a wellbore, or among different wells); the extremes of high or low permeability are critical; the predominant variation in sands is usually vertical (Cardium is an example) while that in reefs is often horizontal (Keg River reefs are examples).

Favourable rock and fluid properties means - relatively high average level of porosity and permeability; low oil viscosity; and capillary pressure, relative permeabilities, and wettability complementing the drive mechanism.

5. Regarding a homogeneous or randomly heterogeneous reservoir with unfavourable rock and fluid properties, the Board is uncertain about the effect of production rate on recovery and believes caution is warranted in setting individual well rates.

6. In stratified reservoirs with favourable rock and fluid properties, and subject to 3, high individual well production rates may have an adverse or a beneficial effect on pool recovery depending on circumstances (e.g. well location, strata position, formation dip, etc.) and detailed investigation is required.

7. In stratified reservoirs with unfavourable rock and fluid properties, high individual well rates can adversely affect volumetric sweep efficiency and individual well recovery and thereby prejudice the opportunity for recovery by adjacent wells. In this case recovery will be sensitive to well production rates and schedules and these must be part of an overall depletion plan.

Effect of Pool Production Rate on Recovery

8. In any situation, pool recovery will be reduced if a change in pool production rate changes the pore-to-pore displacement and/or the volumetric sweep efficiencies such that the integrated value for all drive mechanisms is reduced.

9. In a homogeneous reservoir with favourable rock and fluid properties, and subject to 3 and 8, the pool production rate may be varied over a wide range without significantly affecting the pool recovery.

10. Regarding a homogeneous reservoir with unfavourable rock and fluid properties the Board is uncertain about the effect of pool production rate on recovery and believes caution is warranted.

11. In a randomly heterogeneous or a stratified reservoir with otherwise favourable rock and fluid properties, and subject to 3 and 8, pool production rate can be varied over a wide range without significantly affecting oil recovery.

12. Regarding a randomly heterogeneous or a stratified reservoir with unfavourable rock and fluid properties the Board is uncertain about the effect of production rate on recovery and believes a detailed reservoir study and pool depletion plan are required to ensure maximum recovery.

6.33 Externally-Caused Displacement By An Immiscible Fluid - Horizontal Floods

In horizontal displacement processes the immiscible displacing fluid is usually water, but natural gas is injected in a few cases. Immiscible displacements are considered to be piston-like when the physical properties of the rock and fluids are such that all the recoverable oil is obtained simultaneously with the breakthrough of the displacing fluid. Horizontal displacement by water is sometimes piston-like, but a subordinate production phase during which significant quantities of oil are recovered usually follows gas or water breakthrough. Thus, depending upon the rock and fluid properties, the pore-to-pore displacement efficiency can be affected by the volume of displacing fluid passed through the portion of the reservoir concerned.

The volumetric sweep efficiency in horizontal floods is often considered to be the composite of a vertical sweep efficiency (vertical conformance) and an areal one. The vertical sweep efficiency depends primarily on the stratification (vertical distribution of permeability of the reservoir rock), the mobility ratio, the effect of gravity on fluid over-ride or under-run and, to some extent, upon the spacing pattern. The permeability distribution and mobility ratio both affect the degree of cross-flow between layers. All performance prediction methods for horizontal displacement processes attempt to account for the vertical heterogeneity of the reservoir. Some methods assume the reservoir to be made of layers that are continuous from well to well. These methods allow for differences in the properties of the layers and involve the calculation of the production of individual layers and summing them to obtain a production forecast for the complete section. The areal sweep efficiency is primarily affected by the mobility ratio, the flooding pattern, and the quantity of displacing fluid injected. Correlations of the sweep efficiency with mobility ratio and volume of displacing fluid injected have been presented in the literature for most flood patterns. The correlations show that, regardless of flood pattern, the areal sweep efficiency to breakthrough and the increase in areal sweep efficiency with continued injection after breakthrough both decrease as the mobility ratio increases.

Although it is conceptually useful to consider the recovery from horizontal floods to be the composite of the pore-to-pore displacement efficiency and vertical and areal sweep efficiencies, it should be remembered that these are all average efficiencies and the actual recovery varies widely from place to place. Numerical simulation techniques better approximate the actual situation since they permit considerably more sophisticated calculations which account for the spatial distribution of fluids and the effects of cross-flow, gravity segregation, and capillary imbibition.

It is generally accepted that production rate can have a significant effect on the performance characteristics (i.e. GOR, WOR, reservoir pressure) of horizontal displacement processes. In water-floods, increased production rates permit economic operation to higher limiting WORs which results in the passage of more water through the reservoir thereby improving the pore-to-pore displacement efficiency. Increased production rate also causes earlier breakthrough and reduced recovery per unit volume of water injected. The effect of increased rates in gas-floods is similar to that in water-floods except that due to the additional costs associated with gas compression, the economics are not as favourable. The overall effect of production rate on ultimate recovery from horizontal displacement processes is somewhat controversial and varies from case to case.

6.331 Views of the Participants

Board Staff

The Board staff stated that the recovery efficiency of a horizontal displacement process was largely controlled by reservoir heterogeneity and stratification, flooding pattern, and mobility ratio. It said that high production rates could reduce oil recovery as a result of bypassing of the oil due to irregular advances of fluid interfaces, viscous fingering under adverse mobility conditions and, with water-wet reservoir rocks, insufficient time for effective capillary imbibition.

The Board staff did not submit laboratory, numerical simulation, or field studies to verify its contention. In response to questions, it

contended that there was a deterioration in the performance (i.e. observed WORs and reservoir pressures) of some horizontal water-floods which correlated with the high allowables of recent years. It considered water breakthrough in some Beaverhill Lake and Cardium pools to be evidence of an adverse effect of production rate on oil recovery. The Board staff pointed out that the chance of significant losses due to the sensitivity of recovery to production rate was greatest in the early and middle stages of depletion and that unrestricted rates could and should apply in the late stages of flooding if this would extend the economic producing life.

Ashland

The Ashland submission was concerned with horizontal water-flooding of sandstone reservoirs. The Neotec study submitted by Ashland reviewed the state of the art concerning water-flooding and identified the following as the key factors influencing horizontal flood performance: mobility ratio, heterogeneity, wettability, imbibition, gravity segregation, coning, and frontal stability (viscous fingering). It acknowledged that there were uncertainties concerning frontal instability phenomena. It stated that imbibition was a relatively rapid process in water-wet rocks but irrelevant to water-flood recovery from oil-wet rocks. It said that frontal instability was dampened by the action of reservoir heterogeneity and by capillary and gravity forces. Neotec concluded that mathematical simulation was the best means of evaluating the effect of rate on oil recovery and that, given reliable basic reservoir description (boundary conditions and rock and fluid properties) future performance could be predicted with confidence.

Neotec used a two-dimensional coning model to study several water-wet reservoir rock-fluid systems subject to water displacement with full pressure maintenance. The results of their studies are summarized in Table 6-3. The radial model had eight radial blocks, twelve 2-ft layers, an internal radius of 5 ft and an external radius of 689.1 ft.

The Neotec model predictions showed that:

1. Increased production rate had a consistent beneficial affect on recovery.

2. Recovery was generally reduced with increased heterogeneity although the spatial position of heterogeneities must be considered in evaluating the effect of rate on recovery.

TABLE 6-3

SUMMARY OF THE RESULTS FROM NEOTECH'S CONING MODEL STUDIES OF HORIZONTAL WATER-FLOODS

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Fluid Production Rate bbl/d/well	Recovery At Econ. Limit† Per cent	Performance Characteristics: Recovery At Breakthrough Per cent	Cumulative WOR bbl/bbl	Producing Life Years
1	Homogeneous Case							
1(a)	k_h = 93 md	μ_o = 2.5 cp	P_c = 6 → 0 ++	60	35.5	21.5	0.91	40.4
	k^h = 27 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	41.6	21.6	2.06	29.7
	ϕ^v = 0.195	B_o^w = 1.15	S_{or} = 0.22	400	46.2	21.6	3.85	19.5
				600	47.8	21.5	4.38	16.4
1(b)	k_h = 93 md	μ_o = 2.5 cp	P_c = 40 → 0 +++	60	33.2	21.2	0.77	35.3
	k^h = 27 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	38.5	22.3	1.74	24.7
	ϕ^v = 0.195	B_o^w = 1.15	S_{or} = 0.22	400	42.2	22.2	3.49	16.5
1(c)	k_h = 2790 md	μ_o = 25.0 cp	P_c = 6 → 0	60	23.9	13.5	0.72	26.2
	k^h = 810 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	28.5	13.5	1.88	20.5
	ϕ^v = 0.195	B_o^w = 1.15	S_{or} = 0.22	400	33.8	13.2		
1(d)	k_h = 2790 md	μ_o = 25.0 cp	P_c = 40 → 0	60	22.7	12.8	0.94	27.6
	k^h = 810 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	28.8	14.0	1.85	20.4
	ϕ^v = 0.195	B_o^w = 1.15	S_{or} = 0.22					
2	Layered Case (Most permeable layers at bottom)							
2(a)	k_h = 1.5 - 400 md	μ_o = 2.5 cp	P_c = 6 → 0	60	26.0	11.2	0.99	31.5
	k^h = 0.15 - 150 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	30.0	10.9	2.19	22.4
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	S_{or} = 0.22	400	33.6	9.8	4.32	15.8
				600	34.4	9.2	5.49	13.2
2(b)	k_h = 1.5 - 400 md	μ_o = 2.5 cp	P_c = 40 → 0	60	30.1	11.9	0.91	35.1
	k^h = 0.15 - 150 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	34.5	11.7	2.03	24.9
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	S_{or} = 0.22	400	37.1	10.5	4.29	17.4
2(c)	k_h = 45 - 12000 md	μ_o = 25.0 cp	P_c = 6 → 0	60	20.0	6.5	1.00	25.4
	k^h = 4.5 - 4500 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	23.3	6.1	1.91	17.1
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	S_{or} = 0.22	400	24.6	5.9	4.54	12.7
3	Inverted Layered Case (Most permeable layers at top)							
3(a)	k_h = 1.5 - 400 md	μ_o = 2.5 cp	P_c = 6 → 0	60	36.5	13.8	1.03	44.3
	k^h = 0.15 - 150 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	39.5	12.7	2.51	32.3
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	S_{or} = 0.22	400	39.8	11.3	5.13	21.4
3(b)	k_h = 1.5 - 400 md	μ_o = 2.5 cp	P_c = 6 → 0	60	32.0	8.6	0.99	38.3
	k^h = 0.15 - 150 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	400	35.5	6.8	5.37	19.6
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	S_{or} = 0.22					
4	Random Case (Random distribution of ϕ and k)							
4(a)	k_h = 1.0 - 3885 md	μ_o = 2.5 cp	P_c = 6 → 0	60	34.5	23.2	0.60	36.7
	k^h = 0 - 1385 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	150	38.1	21.5	1.65	25.9
	ϕ^v = 0.15 - 0.25	B_o^w = 1.15	S_{or} = 0.22	400	40.3	19.8	3.59	17.1
4(b)	k_h = 1.0 - 3885 md	μ_o = 2.5 cp	P_c = 40 → 0	60	33.5	22.7	0.56	35.0
	k^h = 0 - 1385 md	μ_o^w = 0.75 cp	S_{wi}^c = 0.45	400	40.4	21.2	3.32	16.2
	ϕ^v = 0.15 - 0.25	B_o^w = 1.15	S_{or} = 0.22					
5	Layered Case With Layer Properties							
5(a)	k_h = 1.5 - 400	μ_o = 2.5 cp	P_c, k_r, S_{wi}	60	36.2	5.0	0.67	36.2
	k^h = 0.15 - 150	μ_o^w = 0.75 cp	different for	150	39.0	4.5	1.71	24.9
	ϕ^v = 0.17 - 0.245	B_o^w = 1.15	each layer	400	41.0	4.9	3.50	16.8
				600	42.5	3.9	4.92	14.5
5(b)	As in 5(a)	60 bbl/d to breakthrough, increase to 400			40.5	5.0	3.72	1[illegible]
		150 bbl/d to breakthrough, increase to 400			41.0	4.5	3.68	1[illegible]
5(c)	As in 5 (a)	60 bbl/d to 25.0% recovery, increase to 400			41.1	5.0	3.11	40.0
		150 bbl/d to 25.0% recovery, increase to 400			41.1	4.5	3.29	20.0
5(d)	As in 5(a)	60 bbl/d to 36.2% recovery, increase to 400			41.9	5.0	2.33	43.0
		150 bbl/d to 39.0% recovery, increase to 400			41.9	4.5	2.75	29.3
		400 bbl/d to 41.0% recovery, increase to 600			42.3	3.9	4.25	18.4
5(e)	As in 5(a)	Oil rate of 60 bbl/d increasing to 400			40.8	5.0	2.49	26.5

†Data at the Economic Limit

Fluid Rate bbl/d/well	Final Oil Rate bbl/d/well	Final WOR bbl/bbl
60	10.5	4.7
150	11.9	11.5
400	15.8	24.4
600	18.8	30.8

++Maximum oil-water capillary pressure 6 psi decreasing to 0 psi at S_{or} = 0.22

+++Maximum oil-water capillary pressure 40 psi decreasing to 0 psi at S_{or} = 0.22

3. Increased viscosity had an adverse effect on recovery both at breakthrough and the economic limit.

4. Increased capillary pressure had a variable effect on recovery:

   (a) an adverse effect for the homogeneous and the inverted-layer cases;

   (b) a beneficial effect for the layered case.

On the basis of this study Ashland concluded that for horizontal water-floods the optimum recovery was attained at the maximum rate of production and injection that can be handled by the wells in a given reservoir.

In a letter transmitting further information that had been requested by the Board, Ashland stated:

> "Without considering costs and present worth (project life) it appears that large increases in water throughput are required to obtain relatively small increases in oil recovery. However, if one considers economic factors the relatively small gain in ultimate oil recovery can be obtained at reasonable cost. Assuming that facilities are installed initially to handle anticipated volumes of water, the incremental cost to lift, treat, and reinject the incremental water is small relative to the fixed costs and additional oil revenue. This situation would improve if net oil price (after royalty) increases faster than increases in operating costs. If one also considers increases in present worth resulting from reduced life, then for the cases we have studied it is clear that the higher producing rate with the attendant higher cumulative water injection is the most attractive depletion scheme".

Home

Home presented a summary of the factors that it stated would control oil recovery under water-flood and commented on the possible relation of production rate to each factor. Home stated that capillary imbibition was not significant since it considered most Alberta reservoirs to be intermediate- or oil-wet. In addition, Home referred to the recent work of McCaffery[25] which suggested that contact angle hysteresis would significantly reduce the effectiveness of imbibition processes even in the water-flooding of water-wet rocks.

Home performed some numerical model studies to investigate the sensitivity of recovery to production rate in horizontal water-flooding of the Swan Hills Beaverhill Lake A & B Pool. Cross-section models were prepared for reef-rim and reef-lagoonal facies. The model corresponded

to a rectangular 320-acre tract, half a mile wide by one mile long. The cross-section consisted of an injection well and a producing well separated by nine grid blocks each 293 ft in length. The model was run in a two-phase mode (oil and water). The oil PVT properties allowed for shrinkage but it was assumed that no free gas saturation would develop. The capillary pressure was assumed to be zero since Home considered that contact angle hysteresis would render the imbibition insignificant, if not absent. The results of Home's studies are summarized in Table 6-4.

The predicted recovery at the economic limit for the reef-rim cross-section was relatively insensitive to the production rate. The economic limit varied from 20 to 50 bbl/d and the final WORs from 4 to 19 bbl/bbl for fluid production rates of 100, 300, 600, and 1,000 bbl/d. The predicted recovery at breakthrough was lower for the higher production rates and significantly more water was produced to the economic limit than for the lower production rate cases.

The model of the reef-lagoonal facies showed an increase in oil recovery from 36.7 per cent to 45.3 per cent for an increase in fluid production rate from 100 to 1,000 bbl/d. Water breakthrough occurred earlier, relative to cumulative oil recovery, and the WOR climbed more rapidly for the lower oil production rates. This result was opposite to the model predictions for the reef-rim facies and was not discussed by Home. Home attributed the recovery increase for all high-rate cases to the larger volume of water cycled and the better flushing of strata.

Imperial

To study the influence of production rate on the recovery of oil by horizontal displacement by water Imperial used, for the first case, a cross-sectional model consisting of 17 vertical grid layers each 11.5 ft thick, a 0.6^{o} dip, and 13 horizontal grid blocks each 574.38 ft long. Reservoir rock and fluid properties were taken to be typical of those found in the Judy Creek Beaverhill Lake B Pool. The injection and production completion intervals covered the full face of the cross-section.

Predictions were made for fluid production rates of 100, 500 and 1,000 bbl/d. On the basis of actual Judy Creek field costs, Imperial estimated the economic oil-producing limit for each case to be 22, 28 and 5 bbl/d respectively. The results of this study are shown in Table 6-5.

TABLE 6-4

SUMMARY OF THE RESULTS FROM HOME'S CROSS-SECTIONAL MODEL STUDIES OF HORIZONTAL WATER-FLOODS

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Fluid Production Rate bbl/d/well	Recovery At Econ. Limit† Per cent	Performance Characteristics: Recovery At Breakthrough Per cent	Cumulative WOR bbl/bbl	Producing Life Years
	Reef Rim Case							
1	k_h = 2.0 - 59.7 md	$\mu_o \simeq 0.33$ cp	$P_c = 0$	100	46.7	38.9	0.12	200
	k_h = 0.0 - 38.4 md	$\mu_w = 0.29$ cp	$S^c_{wi} = 0.136$	300	47.1	36.9	0.97	110
	ϕ^v = 0.065 - 0.187	$B_o \simeq 1.56$	$S_{or} = 0.34$	600	46.2	32.1	1.31	62
				1000	46.9	26.5	2.02	50
	Reef Lagoonal Case							
2	k_h = 0.3 - 8.3 md	$\mu_o \simeq 0.33$ cp	$P_c = 0$	100	36.7	13.4	0.66	133
	k_h = 0.0 - 2.1 md	$\mu_w = 0.29$ cp	$S^c_{wi} = 0.136$	300	41.3	15.9	1.15	62
	ϕ^v = 0.034 - 0.10	$B_o \simeq 1.56$	$S_{or} = 0.34$	600	42.5	16.3	1.40	36
				1000	45.3	17.0	1.78	28

†Data at the Economic Limit

Fluid Rate bbl/d/well	Final Oil Rate bbl/d/well	Final WOR bbl/bbl
100	20	4
300	30	9
600	40	14
1000	50	19

TABLE 6-5

SUMMARY OF THE RESULTS FROM IMPERIAL'S CROSS-SECTIONAL MODEL STUDIES OF HORIZONTAL WATER-FLOODS

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Fluid Production Rate bbl/d/well	Recovery At Econ. Limit† Per cent	Performance Characteristics: Recovery At Breakthrough Per cent	Cumulative WOR bbl/bbl	Producing Life Years
1	Beaverhill Lake Cross-sectional Model							
1(a)	k_h = 4.8 - 1887 md	$\mu_o \simeq 0.32$ cp	$P_c = 50 \rightarrow -50$††	100	57.9	44.7	0.10	82.2
	k_h = 0.003 - 1 md	$\mu_w = 0.44$ cp	$S^c_{wi} = 0.08$	500	63.4	47.9	0.67	27.4
	ϕ^v = 0.025 - 0.10	$B_o \simeq 1.65$	$S_{or} = 0.25$	1000	63.7	47.8	0.71	14.0
1(b)	As in 1(a) 400 bbl/d to 37.8% recovery, 650 bbl/d to 56.7% recovery, increase to			1000	63.0	45.2	0.74	23.0
2	Thick Layered System (16.7 ft)							
2(a)	k_h = 1.41 - 60.54 md	$\mu_o \simeq 0.32$ cp	P_c different	100	57.8	46.8	0.21	90.4
	k_h = 0.14 - 6.05 md	$\mu_w = 0.44$ cp	for each layer	500	55.6	45.7	0.23	17.8
	ϕ^v = 0.09	$B_o \simeq 1.65$	$S_{wi} = 0.08$	750	56.1	44.6	0.32	12.7
2(b)	As in 2(a) except capillary pressure set to zero			100	58.1	**	0.22	**
				500	57.1	**	0.45	**
2(c)	As in 2(a) except gravity forces set to zero			100	53.2	**	0.12	**
				500	55.9	**	0.29	**
2(d)	As in 2(a) except both capillary pressure and gravity forces set to zero			100	54.8	**	0.16	**
				500	58.2	**	0.64	**
2(e)	As in 2(a) except layers were inverted			100	57.0	39.3	0.25	91.8
				500	57.9	38.5	0.56	23.3
3	Thin Layered System (5.6 ft)							
3(a)	k_h = 1.41 - 60.54 md	$\mu_o = 0.32$ cp	P_c different	100	57.8	52.3	0.09	79.4
	k_h = 0.14 - 6.05 md	$\mu_w = 0.44$ cp	for each layer	500	59.2	44.7	1.10	32.1
	ϕ^v = 0.09		$S_{wi} = 0.08$					
3(b)	As in 3(a) except layers were inverted			100	55.2	46.6	0.10	72.6
				500	52.9	47.2	0.33	19.5

†Data at the Economic Limit

Fluid Rate bbl/d/well	Final Oil Rate bbl/d/well	Final WOR bbl/bbl
100	22	3.5
500	28	16.9
750	31	23.2
1000	51	18.5

††Maximum oil-water capillary pressure 50 psi decreasing to 0 psi at $S_w \simeq 0.36$ and to -50 psi at $S_w = 0.75$

**Data not available

The results of Case 1(a) indicated an oil recovery at water breakthrough of 44.7 to 47.9 per cent with the earliest breakthrough occurring at the lowest production rate. Imperial attributed this to gravity slumping. Ultimate recovery at the economic limit for the 1,000 bbl/d case was 5.8 per cent and 0.3 per cent higher than for the 100 and 500 bbl/d cases respectively. It was predicted to be economical to produce and cycle over seven times as much water at 1,000 bbl/d than at 100 bbl/d.

Case 1(b) showed the effect of a progressively increasing production rate schedule (400-650-1,000 bbl/d). The recovery was 0.7 per cent less than for the constant 1,000 bbl/d production rate and Imperial stated that:

> "The study demonstrates that the ultimate recovery achieved under a schedule of progressive rate increases is less than for the case where no rate restrictions were imposed at any stage of depletion. From this it is concluded that no conservation benefits will be achieved by artificially limiting withdrawal rates during the early stages of depletion for typical Beaverhill Lake reservoirs. There is a definite risk that lack of economic incentive to install facilities later in the life of a reservoir will result in a loss in recovery".

Case 2 was simulated by a cross-sectional model having 16.7 ft thick horizontal layers of alternating high and low permeability selected to have a coefficient of permeability variation of 0.75. This case had the same fluid and rock-fluid properties as Case 1 except that the J-function was used to vary the capillary pressure from layer to layer. The predictions indicated that, for a system that would spontaneously imbibe water to a saturation of about 37 per cent, recovery could be increased by 2.2 per cent by reducing the reservoir production rate from 500 to 100 bbl/d. However, at 750 bbl/d, the predicted recovery to the economic limit was 0.5 per cent greater than for the 500-bbl/d case. Imperial said these results challenged the classic MER concept of ever-decreasing recovery with increasing production rates.

Cases 2(b), 2(c), and 2(d) investigated the relative importance of capillary pressure, gravity segregation, and viscous displacement to the horizontal water-flood process. From the results of these cases Imperial concluded that:

> "the effects of viscous cross-flow predominate in recovery from this model. Capillary and gravity forces play only a subordinate role in ultimate recovery as demonstrated by the small effect of eliminating these forces. The cases in which only viscous effects are modelled yield recoveries ranging from 54.8% to 58.2% OIP which is virtually the same as the recovery obtained when capillary and gravitational forces are included. These cases also indicate that even though the elimination of capillary pressure significantly reduced the time to water breakthrough, recovery to economic limit was improved. This model demonstrates that recovery to water breakthrough should not be used as an indication of total recovery".

Case 3(a) was identical to Case 2(a) except that the layer thickness was decreased from 16.7 to 5.6 ft. The effect of cross-current imbibition was not as important in the thin beds, and the predicted recovery was increased by 1.4 per cent by increasing the reservoir production rate from 100 to 500 bbl/d.

The interdependence of gravity and capillary forces with layer position were investigated in cases 2(e) and 3(b) simply by inverting the layer position used in cases 2(a) and 3(a) respectively. The predicted recovery for the 500 bbl/d rate in Case 2(e) was not much different from Case 2(a) but over twice as much water was cycled. Conversely, for the 500 bbl/d rate in Case 3(b) only about one-third as much water was cycled compared to Case 3(a).

From its extended cross-section studies Imperial concluded that capillary, gravity, and viscous forces interacted in a complex manner, that it was extremely difficult to predict the effect of production rate on recovery by investigating the effect of any one force independently, and that rate-recovery phenomena must be studied on an individual reservoir basis.

Other studies performed by Imperial using the Beaverhill Lake cross-section model demonstrated that full-face completion increased recovery from 2 to 6 per cent over that from partial well completions (injection near the base, production near the top). The results generally showed that any measure exposing greater parts of the formation to water flushing tended to increase oil recovery.

To substantiate its view that displacement efficiency was not reduced and in fact would be improved with higher rates, Imperial submitted

performance interpretations for the Judy Creek Beaverhill Lake A and B pools, indicating that flushing efficiencies had slightly increased when production rates had been increased. Imperial emphasized that the absolute value of the flushing efficiency was not the critical factor to be considered in determining whether the flushing efficiency was sensitive to producing rate. It stated that if the flushed zone had been determined consistently, using the same procedures and principles, the relative flushing efficiencies would be meaningful. Imperial stated it had strived for this consistency in its analysis.

Intercomp

Intercomp used numerical simulators to study horizontal displacement by water injection in a Beaverhill Lake carbonate and a Belly River sandstone. They investigated the effect of rate, absolute and relative permeability, capillary pressure, fluid viscosity, and reservoir heterogeneity. Development and operating practices, including flood pattern, injectivity and productivity limitations, allocation of production among wells, and economic limit considerations at abandonment, were not included in the study. Intercomp held that horizontal water-flood displacement in a horizontal, very thin sand would yield a unique curve of pore volumes of oil produced versus water injected, completely independent of the flooding rate used. It stated that gravity drainage and cross-current imbibition were time-dependent phenomena which required study to determine the extent to which oil recovery was dependent upon production rate.

Intercomp used a radial-flow coning model to study the effect of production rate on recovery from a single-well reservoir having properties taken to be typical of the Swan Hills field. The model represented a reservoir with twelve layers each 10 ft thick, an external radius of 1,490 ft, and a well perforated full face. To simulate full pressure maintenance water was injected full face around the outer boundary. Peripheral water injection rates of 500, 2,000 and 5,000 bbl/d were used to simulate three initial oil production rate cases of 392, 1,570 and 3,920 bbl/d. The results of these runs are summarized in Table 6-6.

TABLE 6-6

SUMMARY OF THE RESULTS FROM INTERCOMP'S MODEL STUDIES OF HORIZONTAL WATER-FLOODS

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Reservoir Voidage Rate bbl/d/well	Recovery At End of Prediction Per cent	Performance Characteristics: Recovery At Breakthrough† Per cent	Cumulative WOR bbl/bbl	Producing Life Years	Fianl Oil Rate bbl/d
1	Swan Hills Single Well Water Flood								
1(a)	k_h = 3.4 - 369 md k_v = 0.27 - 79 md ϕ^v = 0.035 - 0.172	$\mu_o \simeq 0.53$ cp $\mu_o = 0.60$ cp $B_o^w \simeq 1.28$	$P_c = 0$ $S_c = 0.1$ $S_{wi} = 0.43$ S_{or}	500 2000 5000	52.0 52.8 52.9	20.5 13.7 5.4	2.47 6.92 11.98	132 73 47	5 5 5
1(b)	Same as 1(a) except initial pressure was only 230 psi above bubble point			500 2500	47.7 52.0	12.6 4.5	5.49 20.89	219 158	7.8 5
2	Belly River B Pool Cross-Section								
2(a)	k_h = 0.1 - 233.1 md $k_h = 0.1\ k_h$ ϕ^v = 0.11 - 0.234	$\mu_o \simeq 2.5$ cp $\mu_o = 0.7$ cp $B_o^w \simeq 1.12$	Variable P_c and S_{wi} $S_{or} = 0.21$	100 200 400	44.7 50.5 53.0	18.0 17.6 17.4	2.45 5.18 8.55	164 164 134	7 5 5
2(b)	As in 2(a) except $P_c = 0$			100 200 400	34.9 43.2 48.8	11.7 11.7 10.9	3.44 6.21 11.80	164 164 164	7 6 5
2(c)	As in 2(a) except P_c = ½ values in Case 2(a)			100 400	43.4 51.9	17.0 16.0	2.56 8.91	164 134	7 5
2(d)	As in 2(a) except layer thickness was increased from 1 ft to 5 ft			100 400	31.0 36.8	12.0 12.5	0.99 2.39	164 164	29 28
2(e)	As in 2(a) except the 30 one-ft layers were combined into 16 layers			400	53.1	16.2	8.42	134	5
2(f)	As in 2(a) except the producing interval covered only three layers instead of full interval			100 400	51.7 54.2	25.0 23.2	1.82 6.27	97 65	5 5
2(g)	As in 2(a) except dP_c/dS_w values were constant for four ranges of permeability			100 400	36.0 47.5	23.0 23.0	0.43 3.51	55 55	12 12
2(h)	As in 2(g) except dP_c/dS_w values were for an oil-wet system			100 400	25.0 37.5	11.7 10.9	1.13 4.5	55 55	15 20
3	Belly River B Pool 3-D Study (1/8 of a 9-spot pattern)								
3(a)	k_h same as 2(e) $k_v = 0.1\ k_h$	$\mu_o \simeq 2.5$ cp $\mu_o = 0.7$ cp $B_o^w \simeq 1.12$	Variable P_c and S_{wi}	37.5 150	41 52	7.4 6.7	2.13 7.8	164 164	2 1
3(b)	As in 3(a) except $k_h = 0.01\ k_h$ for the three most permeabile layers in 5 selected grid blocks.			37.5 150	40 51	8.5 9.0	2.36 8.15	164 164	3 1
4	Countess Mannville B Single Well Water Flood								
4(a)	k_h = 35 - 3060 md k_v = 8 - 1500 md	$\mu_o \simeq 5.58$ cp $\mu_o = 1.0$ cp $B_o^w \simeq 1.12$	$P_c = 0$ $S_c = 0.325$ $S_{wi} = 0.30$ S_{or}	50 200 500 1000	26 42 45 45	0.1 0.1 0.1 0.1	1.30 4.74 8.69 8.11	82 82 66 29	13 6 6 10
4(b)	As in 4(a) except well spacing was reduced from 80 acres to 40 acres			50 200 500 1000	36 45 45 45	0.2 0.1 0.1 0.1	2.30 8.61 8.71 8.71	82 74 29 15	5 1.5 5 11
4(c)	As in 4(a) except the permeability was reduced by a factor of ten			50 200 500	36 45 45	0.0 0.0 0.0	2.29 9.04 10.05	82 76 34	5 1 5
4(d)	As in 4(a) except the oil viscosity was increased to 75 cp			100 200 300	15 24 30	0.0 0.0 0.0	14.10 19.37 24.05	82 82 82	5 5 6

†Water Breakthrough was taken to be the point at which the instantaneous WOR reached 0.01 bbl/bbl

Case 1 indicated that although increased rates caused earlier water breakthrough and significantly greater water production, the recovery to a cut-off oil rate of 5 bbl/d increased with production rate. Case 1(b) indicated that wellbore pressures below the bubble point did not reduce recovery because eventually a stabilized condition occurred where the free gas saturation around the wellbore was at the equilibrium level.

To study the effect of production rate on recovery from the Pembina Belly River B Pool, Intercomp used a two-dimensional model of a vertical cross-section 30 ft thick, 2,640 ft long, and 2,970 ft wide. The grid blocks used were 1 ft thick by 203 ft long by 99 ft wide. Four different capillary and relative permeability functions were used and each layer was assigned values based on its permeability level. Four production rate cases were studied corresponding to water injection rates of 100, 200, and 400 reservoir bbl/d. The result of these predictions are shown in Table 6-6.

Case 2(a) was the base case. The sensitivity of recovery to capillary pressure was investigated in cases 2(b) and 2(c). The four capillary pressure relationships started at 40 psi but different initial saturations, and decreased to 0 psi at a common residual oil saturation (i.e. all rock types would spontaneously imbibe water to the residual oil saturation). While Case 2(b) showed that capillary imbibition was important to the recovery process, Case 2(c) had only one-half the capillary pressure of Case 2(a) but attained nearly the same recovery.

The effect of layer thickness was studied in Case 2(d) where the individual layers were increased from 1 ft to 5 ft. Although the recovery was less after 164 years, the oil production rates at that time averaged 29 bbl/d. Had the prediction been continued to the lower final oil rates used in Case 2(a), additional recovery would have been obtained. None the less, greater recovery was predicted for higher production rates.

Case 2(e) showed that the predicted recoveries could be adequately described by lesser vertical definition of heterogeneity. In this case the adjacent 1-ft layers of similar permeability range were combined, resulting in 16 layers varying from 1 to 4 ft thick.

The effect of completion interval on predicted recovery was studied in Case 2(f). The producing well was completed in the three most permeable layers and k_v for these layers were increased tenfold. Although recovery was again predicted to increase with production rate, this case showed the least sensitivity of recovery to production rate.

The effect of wettability was investigated by changing the capillary pressure relationships. In Case 2(g) four synthetic water-wet capillary pressure relationships were used having dP_c/dS_w values that were constant over the full range of displaceable oil saturation and proportional to the square root of the absolute permeability. Case 2(h) applied four synthetic oil-wet capillary pressure relationships having dP_c/dS_w values of equal magnitude but opposite sign to those used in Case 2(g). The predicted recoveries from Case 2(g) were nearly the same as those of the base case at comparable times; however, those of Case 2(h) were identical with Case 2(b) at comparable times. Intercomp stated that this was because of the negligible effect of gravity on oil recovery from this system; had the gravitational effect been greater the oil-wet case would have given less recovery because the capillary pressure would have retarded oil drainage from tight layers. It also stated that a mixed wettability condition which would permit film drainage as postulated by Salathiel may not be beneficial in a horizontal displacement process where imbibition among heterogeneous layers made a significant contribution to oil recovery.

A three-dimensional simulation for 1/8 of an inverted nine-spot pattern was made using a 6 by 6 grid with 16 layers. The rock and fluid properties were the same as used for the cross-section studies of the Pembina Belly River B Pool. The system had two producing wells and the side well reached its cut-off oil rate before the corner well. The injection rate was halved when the side well was shut in. Two injection rates were studied corresponding to full-well production rates of about 90 and 360 bbl/d. For the 3/8 of a producing well contained in the octant these rates corresponded to reservoir voidage rates of 37.5 and 150 bbl/d. The results are summarized in Table 6-6. As in the cross-sectional cases, higher recovery was predicted for the higher production rate.

Intercomp modelled a single well in the Countess Upper Mannville B Pool to study the effect of production rate on water-flood recovery from a heavy-gravity crude reservoir underlain by water. The model consisted of seven radial increments and ten vertical layers. Eight layers were used to represent the 23-ft oil column and 3-ft layers were used for both the transition zone and the water zone. Full pressure maintenance was simulated by full-face water injection around the outer periphery of the model.

In the base case the well was completed in the upper 6 ft of the oil zone and predictions made for reservoir voidage rates of 50, 200, 500, and 1,000 bbl/d. The WOR was predicted to be essentially independent of production rate and recovery increased with production rate.

In case 4(b) the outer radius was decreased to correspond to 40 acres (80 acres was used in the base case) and the completion interval was increased to include the upper 19 ft of the oil zone. The WOR was again predicted to be essentially independent of production rate and recovery increased with production rate.

The permeability was reduced 10-fold in Case 4(c) but the predicted WOR and recovery were essentially the same as in case 4(b).

In case 4(d) the low permeability from case 4(c) was retained but the oil viscosity was increased to 75 cp. The predicted WOR differed from previous cases but was essentially the same for reservoir voidage rates of 100, 200, or 300 bbl/d. Recovery was again predicted to improve with increased production rate.

Intercomp also made runs with an extended oil relative-permeability curve such that the residual oil saturation could be decreased to 10 per cent. Again essentially the same WOR performance was predicted for all rates and recovery predicted to increase with production rate.

In the last case studied capillary pressure was considered, but the predicted performance and recovery were essentially the same as case 4(b).

Intercomp concluded that the dominant mechanisms in the horizontal water-flooding process were viscous displacement laterally (at highly variable rates in layers of different permeability) and counter-current

imbibition normal to the main, horizontal direction of flow. When counter-current imbibition was absent (zero capillary pressure), oil recovery at a given time and rate was lower than with imbibition, confirming that cross-current imbibition into tight layers was a time-dependent process. Intercomp argued that even though imbibition was time dependent it generally did not adversely effect ultimate oil recovery because capillary forces, being high in tight rocks, had only to act over short distances and the imbibition process was therefore nearly instantaneous. It was shown that capillary pressure could be halved with little effect on the predicted recovery.

Texaco Exploration

Texaco Exploration developed its arguments concerning horizontal displacements by frontal advance using the fundamental fractional flow and continuity concepts developed by Leverett and Buckly[26,27]. It assumed that the gravity and capillary pressure terms could be omitted from the fractional-flow equation and that, in a thin homogeneous linear system under horizontal water-flood, rate affected recovery only by determining the limiting water-oil ratio. Texaco Exploration stated that for such a system high rates would tend to increase recovery.

For multi-layer systems with cross-flow occurring, Texaco Exploration reasoned that recovery would be reduced if the flooding rate were high enough for the economic limit to be reached before attainment of capillary pressure equilibrium throughout most of the system.

After applying a safety factor of ten to the Intercomp analysis, which indicated that imbibition would be essentially complete in 70 days, and considering conditions for a single-layer, 160-acre five-spot in the Pembina Cardium Pool, Texaco Exploration proposed that with an average permeability of less than 180 md the physical limits of well capacity were such that recovery was not rate sensitive. As additional layers were added, the time to achieve capillary pressure equilibrium would be extended and the critical permeability level reduced. For thicker reservoirs and higher-viscosity oils the trend would be the same. By this reasoning Texaco Exploration proposed that a cut-off value for the group, $kh/\mu V$, could be used to estimate where the time-dependent phenomena of gravity drainage and imbibition might be important. It suggested that

oil recovery from horizontal water-floods could be considered insensitive to production rate if kh/μV was less than 4,000 to 5,000 md-ft/cp.

6.332 Views of the Board

The Board acknowledges the detailed studies performed by several industry participants and the contribution these studies have made to the understanding of the effect of production rate on oil recovery in pressure-maintained horizontal water-floods.

The Board observes that its staff and the industry participants take opposing positions respecting the effect of production rate on oil recovery in horizontal water-floods. Apparently doubting the validity of predictions based on numerical simulation studies which could not fully account for all factors, and in the light of its interpretation of some historical pool performance data, the Board staff contended that high rates could be detrimental to oil recovery. The industrial participants contended that high rates were not detrimental to recovery because numerical simulation studies indicated increased rates tended to improve ultimate recovery when economic factors were considered. The Board believes the two points of view need not be in conflict but should and do complement each other. The Board notes that industry's predictions show that high production rates cause unfavourable performance, (i.e. high WORs) but when provision is made for this performance and wells are produced to the predicted economic abandonment rate the result can be an increase in recovery.

There was general agreement among the participants that numerical simulators provide a powerful tool for the analysis of sensitivity of recovery to production rate and that performance predictions are reliable to the extent that the reservoir description and the rock, fluid, and rock-fluid properties are representative of the reservoir. Thus the areas of concern are - how representative are the rock and fluid properties, how well do reservoir simulators represent actual pool development and operating practices, and how important is it to relate a study to historical performance data. The Board's views on the effects of physical properties on recovery and sensitivity of recovery to production rate were given in Section 6.2 and are not discussed further here.

The Board shares some of its staff's concern as to how accurately reservoir simulators represent pool development and operating practices. Most of the simulations analysed individual wells assuming radially symmetric rock and fluid properties. Such assumptions tend to assure uniform advance of injected water. These models do not consider areal conformance or the effects of regional heterogeneity. The Board remains unconvinced that studies based on single-well cross-sectional models with symmetrical radial flow are adequate to draw the universal conclusion that high rates are not detrimental to horizontal water-floods. It recalls that in some cases of extreme heterogeneity (e.g. Gulf's study[28] of the performance of Zama reefs) it has been necessary to use three-dimensional coning models to match the production performance. It does accept, however, that high production rates in fully pressure maintained water-floods will increase displacement efficiency and ultimate recovery provided it is economical and practical to cycle large volumes of water.

The Board believes that past experience and performance data require consideration and full explanation. Some performance predictions have proved over-optimistic, particularly for low-permeability and heterogeneous reservoirs such as the Cardium. In these cases a thorough review of the laboratory and geologic data, the assumptions made, and the field performance data is required to provide adequate explanation of the differences between the performance predicted and actual behaviour.

The Board notes that the average rate of flood-front advance in several horizontal water-floods in Alberta has exceeded 2 ft/d. In uniform high-permeability sands such as those of the Joffre Viking Pool these rates do not appear to have been detrimental to ultimate recovery. In such cases the post-breakthrough recovery has been small and it appears that displacement by viscous flow has dominated and capillary imbibition has not contributed materially to recovery. On the other hand, heterogeneous low-permeability pools such as Crossfield Cardium have performed much below expectations. There is much uncertainty about the effects that production rate, reservoir heterogeneity, and wettability have had in this pool.

Although the presence of an equilibrium gas saturation in Intercomp's Case 1(b) did not significantly affect recovery, it was necessary to cycle about twice as much water to achieve the same recovery. The Board also notes some pools have failed to develop an equilibrium gas saturation of the type predicted in Intercomp's study. Some projects in the Pembina Cardium and Belly River pools and Provost Viking Pool have tended to retain the characteristics of a solution gas drive despite the injection of significant volumes of water. At the Leduc-Woodbend D-2B Pool horizontal water-flood has proved relatively inefficient when preceded by the development of a significant free-gas saturation.

The simulation predictions provided by Intercomp, Neotec, and Imperial have demonstrated that capillary imbibition can be rapid compared to the pool depletion life. They indicate that cross-flooding of low permeability lenses may contribute more to oil recovery than the imbibition process. If increased production rates will lead to greater cross-flooding in horizontal water-floods they should be encouraged. It appears to the Board, however, that comprehensive studies of individual patterns are required in some pools in order to determine optimum methods of achieving cross-flooding.

The importance of layer position to oil recovery is clearly demonstrated in the layered and inverted-layer cases of Neotec and Imperial. These studies indicate that careful reconstruction of local pattern performance may be needed to establish whether increased production rates would lead to significantly increased oil recovery.

The Board partially agrees with Imperial's conclusion that there has been no significant change in the flushing efficiency at increased withdrawal rates from the Judy Creek Beaverhill Lake A and B Pools. Imperial's interpretation of breakthrough flushing efficiency exhibits a trend toward increasing efficiency with the advance of the water-flood front. Although the Board considers this significant and encouraging, it believes increasing efficiency should generally be expected as more of the reservoir is flushed by multiple pore-volumes of water. For the relative permeability relationships used in the above pools the average displacement efficiency at breakthrough in a homogeneous rock would be some 53 per cent, increasing to 73 per cent with continued injection of water. While the average flushing efficiency has improved slightly

during a period of increasing rates, an even greater increase might have occurred at a lower rate. That is, an increase would have been expected because of better flushing in portions of the reservoir, but some of the increase may have been offset by less efficient displacement due to channeling and early breakthrough at the water-flood front.

The Board's views on the effect of production rate on recovery from horizontal floods are summarized below.

General

1. Reservoir simulation studies are recognized as a powerful tool for evaluating the effect of production rate on recovery in horizontal displacement processes.

2. The results of reservoir simulation studies are given greater credence when they are accompanied by a good match with historical performance.

Effect of Individual Well Production Rate on Recovery

3. In any situation pool recovery would diminish with increasing well production rate if at the higher rate the producing GOR were larger.

4. In a homogeneous or randomly heterogeneous reservoir with favourable rock and fluid properties*, and subject to 3, individual wells in multi-well pools can be produced at capacity provided it is economically and physically practical to sustain the high fluid production rates after breakthrough.

5. Regarding a homogeneous or randomly heterogeneous reservoir with unfavourable rock and fluid properties, the Board is uncertain about the effect of production rate on recovery and believes caution is warranted in setting individual-well rates.

6. In stratified reservoirs with favourable rock and fluid properties, high individual-well production rates may have either an adverse or a beneficial effect on pool recovery depending on circumstances (e.g. well location, strata position, formation dip, etc.) and detailed investigation is required.

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*See footnotes on page 6-43.

7. In stratified reservoirs with unfavourable rock and fluid properties, high individual-well rates can adversely affect the volumetric sweep efficiency of individual patterns. In this case recovery will be sensitive to well production and injection rates and these must be part of the overall depletion plan.

Effect of Pool Production Rate on Recovery

8. In peripheral floods pool recovery will be reduced if increased pool production rate causes a local or regional solution-gas drive to develop.

9. In pattern floods the pool production rate is taken as the sum of the individual-well or pattern production and injection rates, and the effect of production rate on recovery is the same as covered by items 3 through 7.

Although most of the evidence was for horizontal flooding by water, the Board believes that several of the above views and conclusions are equally applicable to horizontal gas-floods. In the latter case there would be no effects of imbibition, however, gravity segregation would be more important.

6.34 Externally-Caused Displacement By An Immiscible Fluid - Vertical Floods

Immiscible vertical displacement of oil by gas or water in those parts of the reservoir remote from well bores is dominated by capillary and gravity forces. Closer to the well bore, however, viscous forces resulting from pressure drawdown around the bore may become significant and can result in coning of gas, water, or both. The ideal process is a uniform movement of the interface across the entire reservoir, usually as a level surface. This occurs when gravity dominates the process. The process may be enhanced by greater density contrast and also by high permeability, both vertical and horizontal. Higher horizontal permeability results in relatively less coning at producing wells and better lateral distribution of any injected gas or water. Where high vertical permeability and low fluid viscosities are encountered, the

relatively low gravity force is able to maintain equilibrium by a counter-flow process. In some instances tight streaks may be of some benefit by retarding coning.

The total thickness of the oil zone is also important; in thicker zones there is more opportunity for selective completions to avoid irregularities in the interface surface caused by well coning or transition zones. As the remaining oil zone decreases in thickness with continued depletion all wells eventually cone the displacing fluid and reach their economic limit.

As with other recovery processes it is convenient to express the recovery via vertical displacement as the product of the average pore-to-pore displacement efficiency and the volumetric sweep efficiency. For an advancing oil-water interface the former is very sensitive to the water-oil viscosity ratio and rock-fluid properties (wettability and capillary pressure), but is relatively insensitive to production rate since, even at high rates, typical interface movements are in the range of 1-25 ft/yr. On the other hand, the pore-to-pore displacement efficiency of an advancing gas-oil contact is little affected by capillary forces but strongly affected by interface velocity and oil viscosity because of the gravity-drainage of oil.

The volumetric sweep efficiency is largely controlled by the thickness of the remaining oil column (sandwich loss) and its final structural location in the reservoir. This thickness varies with the severity of well coning (a rate-sensitive phenomenon) whereas the location depends on the direction of interface movement. For many reservoirs an oil-water interface moving upward results in the sandwiching of a volume, at the crest of the structure, which is small whereas a gas-oil interface moving downward results in a sandwiched volume which is comparatively large. In some cases the movements of gas-oil and water-oil interfaces are controlled so that a minimum number of well recompletions are required or so as to take advantage of any horizontal heterogeneities (stratification) in the reservoir.

6.341 Views of the Participants

Board Staff

The Board staff submitted that gravity-controlled displacement could be efficient provided there was sufficient vertical permeability and that production rates were controlled to prevent large sandwich losses or other adverse effects of well coning. The Board staff expressed considerable concern about the ability of numerical simulations to properly account for irreversible effects such as capillary hysteresis. It referred to some of the classical methods in the literature for calculating critical coning rates for water and gas and reference rates for gravity drainage.

Atlantic Richfield

Atlantic Richfield focused its arguments on the Bellshill Lake Blairmore Pool. It submitted that recovery from this bottom-water drive pool would be determined largely by individual well performance. Atlantic Richfield maintained that for vertical-drive systems the sensitivity of recovery to the production rate on a pool basis should be distinguished from that on a well basis (e.g. coning). It contended that heterogeneities such as thin horizontal strata with low or negligible permeability could effectively inhibit coning and may be an aid to increased recovery.

Gulf

Gulf submitted that the performance of Devonian reef pools subject to immiscible vertical displacement was not significantly affected by either rate or reservoir heterogeneities. It stated that excessive production rates or pressure decline caused by interference from other pools in a common aquifer could result in substantial shrinkage losses. It contended that the only effect of coning was to increase water disposal or gas conservation requirements, hence recovery costs. Gulf stated that little sensitivity of displacement efficiency to production rate would occur until only the last few producing wells remained. It accepted that the final sandwich loss may depend on well rates during the last few years of depletion. It stated that the only remedies for coning were recompletions or rate reductions and that tests in several D-3 pools indicated

that in many cases water coning could be successfully remedied by rate reductions.

Imperial

Imperial investigated the effect of production rate on the recovery of oil from bottom-water-drive pools in the Leduc reef. It used a coning model with ten grid blocks in the radial direction (internal radius of 1 ft and external radius of 1,489 ft) and thirteen in the vertical direction, with the initial oil zone represented by ten 10-ft layers and the aquifer by three layers of 20, 30, and 50 ft. The rock and fluid properties were taken to be typical of the Redwater D-3 Pool. The producing interval covered the top 20 ft of the oil column and full pressure maintenance was simulated by vertical water injection over the aquifer's entire area. Predictions were made for fluid production rates of 100, 500, 1,000, and 5,000 bbl/d and on the basis of actual operating costs for Redwater, the corresponding economic limits were 5, 7, 19, and 26 bbl/d. The results of this study are shown in Table 6-7.

The results of case 1(a) show that predicted recovery to the economic limit was increased modestly with production rates. Imperial attributed this to better flushing of oil when large volumes of water were cycled. For example, at a fluid production rate of 5,000 bbl/d it was economical to cycle over thirteen times as much water as at 100 bbl/d. When the horizontal permeability was decreased from 5,000 to 500 md in case 1(b) earlier breakthrough occurred along with the need to cycle more water. To investigate whether increased rates would have an adverse effect if the reservoir was oil-wet, Imperial re-ran case 1(a) with relative permeability and capillary pressure relationships characteristic of an oil-wet system. In the oil-wet case, the rock would spontaneously imbibe to a water saturation of about 30 per cent, whereas for the water-wet case it would imbibe to a water saturation of about 55 per cent. While recoveries were predicted to be less for the oil-wet case, increased rates were here, also, observed to result in modestly increased recovery.

A heterogeneous system was studied in case 2 which had a wide range of horizontal and vertical permeabilities. The predictions showed earlier water coning and the need to cycle greater quantities of water

TABLE 6-7

SUMMARY OF THE RESULTS FROM IMPERIAL'S CONING MODEL STUDIES OF VERTICAL WATER DRIVES

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Fluid Production Rate bbl/d/well	Recovery At Econ. Limit† Per cent	Performance Characteristics: Recovery At Breakthrough Per Cent	Cumulative WOR bbl/bbl	Producing Life Years
1	Homogeneous Case							
1(a)	k_h = 5000 md k_h = 10 md ϕ^v = 0.0653	$\mu_o \simeq 2.6$ cp $\mu_o = 0.9$ cp $B_o^w \simeq 1.125$	$P_c = 50 \rightarrow -50$†† $S_{or}^c = 0.25$ $S_{or}^{wi} = 0.25$	100	63.6	50.7	0.44	134.0
				500	64.9	40.7	1.77	53.0
				1000	65.2	38.8	2.95	38.5
				5000	65.8	35.2	6.03	13.7
1(b)	k_h = 500 md k_h = 10 md ϕ^v = 0.0653	$\mu_o \simeq 2.6$ cp $\mu_o = 0.9$ cp $B_o^w \simeq 1.125$	$P_c = 50 \rightarrow -50$ $S_{or}^c = 0.25$ $S_{or}^{wi} = 0.25$	100	62.2	30.6	0.83	169.0
				500	63.8	23.1	2.49	66.0
1(c)	k_h = 5000 md k_h = 10 md ϕ^v = 0.0653	$\mu_o \simeq 2.6$ cp $\mu_o = 0.9$ cp $B_o^w \simeq 1.125$	$P_c = 50 \rightarrow -50$ $S_{or}^c = 0.25$ $S_{or}^{wi} = 0.25$	100	59.3	38.8	0.86	164.4
				500	62.3	27.8	3.15	76.7
				1000	62.7	19.4	4.31	49.3
2	Heterogeneous Case							
2(a)	k_h = 2 - 5000 md k_h = 0.1 - 500 md ϕ^v = 0.0653	$\mu_o \simeq 2.6$ cp $\mu_o = 0.9$ cp $B_o^w \simeq 1.125$	$P_c = 50 \rightarrow -50$ $S_{or}^c = 0.25$ $S_{or}^{wi} = 0.25$	100	54.4	25.0	2.45	276.7
				500	57.7	18.5	6.22	123.3
				1000	58.2	16.7	7.58	74.0
2(b)	As in 2(a) except for the rate schedule 100 bbl/d to 54.4% recovery, increase to			1000	57.8	25.0	6.25	301.4
3	Tight Lenses Case							
3(a)	As in 1(a) except there were 4 isolated lenses (2.5% of oil zone volume)			100	62.3	47.4	0.42	130.0
				500	63.2	40.7	1.58	48.2
				1000	64.0	40.0	3.21	39.7
3(b)	As in 1(a) except there were 13 tight lenses (27% of oil zone volume, 32% of total volume) having P_c values proportional to lens permeability			100	54.2	31.2	1.16	174.0
				500	56.3	17.0	4.47	91.3
	100 bbl/d to 48.8% recovery, increase to			500	56.3	31.2	3.55	152.2
3(c)	As in 1(a) except there were 39 tight lenses (18% of oil zone volume, 30% of total volume) having P_c values proportional to lens permeability			100	53.0	44.4	0.70	133.5
				500	55.6	41.7	3.70	77.2
	100 bbl/d to 47.7% recovery, increase to			500	55.6	44.4	3.13	125.4

†Data at the Economic Limit

Fluid Rate bbl/d/well	Final Oil Rate bbl/d/well	Final WOR bbl/bbl
100	5	19
500	7	71
1000	10	99
5000	26	192

††Maximum oil-water capillary pressure 50 psi decreasing to 0 psi at $S_w = 0.56$ and to -50 psi at $S_w = 0.75$

to achieve lower final recoveries than for the homogeneous cases. Imperial noted that the final oil saturations for comparable model blocks were consistently lower for the higher production rates. This indicated that better conformance was achieved at increased rates and greater water throughout. In a special run to check the sensitivity of the heterogeneous system to increased terminal rates the well was produced to the economic limit corresponding to an initial fluid production rate of 100 bbl/d, increasing to 1,000 bbl/d. The predicted recovery for this rate schedule was 0.4 per cent less than for the constant 1,000 bbl/d case.

Several "tight lens" systems were studied as a further check on the effect of production rate on recovery. In Case 3(a) four tight lenses were isolated at different positions in the otherwise homogeneous matrix. The results showed that the position and permeability of a lens determined whether increased rate was beneficial or detrimental to the flushing of it. The predictions also indicated that the beneficial effect of cycling more water through most of a system operating at higher production rates more than offset any reduced recovery in the tight lenses. In Cases 3(b) and 3(c) Imperial introduced additional tight lenses, each with its own capillary pressure function, and made runs for uniform and variable rates. More tight lenses resulted in less recovery. Nor did a late rate increase improve recovery. Imperial reiterated that the practice of restricting rates early in a pool's life introduced the risk of its becoming impractical to salvage the added reserves obtainable under a schedule of uniformly high rates.

Imperial submitted production performance plots for several Redwater D-3 wells to support the view that substantial reserves could be recovered after breakthrough, that significant rate increases had no obvious detrimental effects to the performance, and that Leduc pools subject to bottom-water drive could be produced to high water-oil ratios.

To substantiate its model predictions Imperial submitted interpretations of oil-water interface movements for the Redwater D-3 Pool which indicated the cumulative flushing efficiency had increased from 63.6 per cent in 1964 (prior to which oil production rates usually averaged 75,000 to 35,000 bbl/d) to 67.5 per cent in December 1973 when rates averaged over 100,000 bbl/d. Imperial concluded that significantly

increased production rates in Redwater had not changed overall pool flushing efficiency. Furthermore, it submitted that the accuracy of calculations improved with continued depletion and that the sensitivity of the flushing efficiency to a ± 5 ft change in oil-water contact had decreased from ± 10 per cent in 1964 to ± 7 per cent in 1973.

Similar interpretations for the Excelsior D-2 showed cumulative flushing efficiencies of 59.4 per cent, 62.7 per cent and 65.2 per cent at December 1960, January 1968 and June 1973, respectively. Pool oil production rates prior to December 1960 declined from 3,000 to 1,200 bbl/d, were in the range 1,600 to 1,100 bbl/d from December 1960 to January 1968, then increased to 3,800 bbl/d in 1973. Imperial presented data to show that the average error in the calculated flushing efficiency for Excelsior had decreased from 3.0 per cent of the oil in place in 1968 to 1.8 per cent in 1973. On the basis of this evidence and other performance indicators Imperial concluded that increased production rates in bottom-water drives were not detrimental to flushing efficiency or ultimate recovery.

Intercomp

Intercomp stated that gravity tended to aid oil recovery since fluid density differences tended to cause drainage of oil upward from below an advancing bottom-water drive or downward from above an advancing gas-oil contact. It submitted that the D-3 reef pools were examples where rapid gravity drainage reduced oil saturation to near-residual values. Intercomp acknowledged that higher rates caused increased coning but submitted that the problem must be examined in detail because the recovery depends not only on reservoir mechanics but on operating conditions such as water disposal capability, artificial lift capacity, and economics.

A single-well Rainbow reef pool was selected for a simulation study of a vertical-drive pool with a propensity for water coning. The well had 350 ft of pay and the top 100 ft were perforated. Pressure maintenance by bottom-water drive for initial oil production rates of 80 and 800 bbl/d were simulated by water injection rates of 100 and 1,000 bbl/d respectively. The external radius of the model increased in four steps down through the upper 80 ft of the oil column and remaining a constant 1,490 ft through the lower 270 ft of the column. Table 6-8 summarizes the several variations that were investigated.

TABLE 6-8

SUMMARY OF THE RESULTS FROM INTERCOMP'S CONING MODEL STUDIES OF VERTICAL WATER-FLOODS

Case No.	Physical Properties: Rock	Fluid	Rock-Fluid	Reservoir Voidage Rate bbl/d/well	Recovery At End of Prediction Per cent	Performance Characteristics: Recovery At Breakthrough† Per cent	Cumulative WOR bbl/bbl	Producing Life Years	Final Oil Rate bbl/d
1	Rainbow Reef Single Well Study (Homogeneous Case)								
1(a)	k_h = 12 md	$\mu_o \simeq 0.59$ cp	Uniform P_c						
	k_h = 12 md	$\mu_w = 0.60$ cp	$S_{wi} = 0.2$	100	19.80	2.6	0.48	164	36
	$\phi^v = 0.08$	$B_o^w \simeq 1.26$	$S_{or} = 0.2$	1000	34.34	2.0	8.60	164	31
1(b)	As in 1(a) except P_c was characteristic of an oil-wet system and $S_{or} = 0.1$			100	19.80	2.7	0.48	164	36
				1000	34.34	2.1	8.60	164	31
1(c)	As in 1(a) except $P_c = 0$			100	26.00	10.4	0.07	164	63
				1000	43.88	2.1	6.49	164	49
1(d)	As in 1(a) except less favourable relative permeability relationships were used			100	13.93	0.8	1.20	164	25
				1000	25.04	0.8	2.30	164	29
2	Rainbow Reef Single Well Study (Stratified Case)								
2(a)	k_h = 3 or 20 md	$\mu_o \simeq 0.59$ cp	P_c different						
	k_h = 3 or 20 md	$\mu_w = 0.60$ cp	for each rock	154	28.92	4.1	0.57	164	39
	ϕ^v = 0.06 or 0.1	$B_o^w \simeq 1.26$	type	920	40.45	3.1	6.49	164	27
2(b)	As in 2(a) except relative permeability and capillary pressure relationships were characteristic of an oil-wet system			154	28.29	3.4	0.61	164	45
				920	43.89	3.1	5.88	164	30
				920	55.00	3.1	17.69	548	7
3	Simonette D-3 Single Well Study								
3(a)	k_h = 44 - 323 md	$\mu_o \simeq 0.11$ cp	Uniform P_c						
	k_h = 1.8 - 30.7 md	$\mu_w = 0.30$ cp	Variable S_{wi}	3000	63.5	6.4	5.34	15	25
	ϕ^v = 0.071	$B_o^w \simeq 2.7$	$S_{or} = 0.26$	15000	64.2	5.6	15.3	6	25
3(b)	As in 3(a) except $P_c = 0$			3000	66.3	24.9	4.10	15	25
				15000	67.0	13.3	10.10	5	25
3(c)	As in 3(b) except two barriers to vertical flow were placed at 40 ft and 76 ft below the top of the reef			3000	67.0	25.6	4.11	15	25
				15000	67.9	14.0	9.38	5	25
3(d)	As in 3(b) except the vertical and horizontal permeabilities were reduced five fold			1000	64.6	17.7	2.75	34	25
				5000	67.2	10.6	6.87		25
3(e)	As in 3(b) except for greater heterogeneity k_h = 4 - 2000 md, $k_h = 0.1\ k_h$, $\phi^v = 0.071^{h}$			3000	67.9	28.8	2.93	12	25
				15000	68.4	25.3	6.03	4	25
3(f)	As in 3(e) except both vertical and horizontal permeabilities were randomly distributed			3000	67.9	16.8	3.02	13	25
				15000	68.4	13.0	7.14	4	25
4	Sturgeon Lake D-3 Single Well Study								
4(a)	k_h = 461 md	$\mu_o \simeq 0.32$ cp	$P_c = 0$						
	k_h = 11 md	$\mu_w = 0.60$ cp	$S_{wi} = 0.15$	375	63	34.0	0.6	14	25
	ϕ^v = 0.047	$B_o^w \simeq 1.5$		1500	65	26.5	1.7	5	25
	$k_{aquifer}$ = 1.34 md								
4(b)	As in 4(a) except $k_{aquifer}$ = 0.134 md			375	65	34.4	0.6	14	25
				1500	66	26.0	1.7	5	25

†Water Breakthrough was taken to be the point at which the instantaneous WOR reached 0.01 bbl/bbl.

Case 1(a) was a homogeneous and isotropic reservoir and the results indicated a significant increase in recovery at the higher rate after 60,000 days (164.3 years). In the first variation studied, a capillary pressure curve for an oil-wet system (spontaneous imbibition would proceed to a water saturation of only 25 per cent compared to 75 per cent for the water-wet case) was simulated by displacing the curve for the water-wet system downward by 35.5 psi. The predicted performance and recovery for this system was identical to the first. Intercomp stated this result was obtained because

> "as long as a single rock type is present, the only important feature of a P_c curve is the slope, dP_c/dS_w; the magnitude cancels out".

In the second variation the capillary pressure was assumed to be zero. In this run the water-oil contact was much sharper and recovery was improved for both rates, with a higher recovery predicted for the higher rate. Less favourable relative permeability relationships were used in the final variation of the homogeneous rock system. This caused earlier water breakthrough and reduced recovery compared with the other cases.

Case 2 was a series of runs for a stratified system comprised of two isotropic rocks with permeabilities of 3 and 20 md. Each rock type was water-wet but characterized by a different capillary pressure relataionship, although both would imbibe to an 83-per-cent water saturation. These runs indicated that stratification could retard water breakthrough at low production rates but would not necessarily be effective at high rates. As before, the higher rates were predicted to increase recovery.

A further two runs were made on the stratified system assuming an oil-wet reservoir rock and appropriate capillary pressure curves. Intercomp said this would be the most severe test of sensitivity of recovery to production rate because the oil must be displaced or drained under circumstances where the capillary forces would preferentially retain oil. It stated that at 80- to 90-per-cent water saturation the very low relative permeabilities for oil may cause oil recovery to be rate and time dependent. The results showed recovery increasing with production rate.

The overall conclusion reached by Intercomp was that regardless of the wettability, capillary pressures, relative permeabilities, and

stratification conditions assumed, the Rainbow reef example well predictions indicated that recovery increased with production rate.

To determine whether early water coning may be detrimental to ultimate recovery from pressure-maintained bottom-water-drive pools containing low-viscosity crude oil, Intercomp performed a series of runs for a Simonette D-3 well. The well had a 116-ft oil column and production was taken from the top 24 ft of pay. Full pressure maintenance by bottom-water-drive was simulated by water injection across the base of the model. Predictions were made for initial oil production rates of 1,000 and 5,000 bbl/d, but because of the high oil shrinkage the corresponding reservoir voidage rates were 3,000 and 15,000 bbl/d. The several variations investigated are summarized in Table 6-8. All predictions were terminated at an oil production rate of 25 bbl/d.

Case 3(a) was the base case and showed earlier breakthrough, higher WORs, and slightly increased recovery for the higher production rate. In Case 3(b) the capillary pressure was assumed to be zero and prediction indicated later water breakthrough, lower WORs, and better recovery than for the base case. Two barriers to vertical flow were simulated in Case 3(c) by setting the vertical permeability to zero in two layers for some 30 ft around the wellbore. This caused only a slight reduction in producing WORs and a slight increase in predicted recovery relative to Case 3(b). The vertical and horizontal permeabilities were reduced five-fold and the production rates decreased three-fold in Case 3(d). These changes increased the producing life and although water breakthrough occurred at a lower oil recovery there was a significant decrease in the quantity of water cycled to achieve oil recoveries comparable to the other cases. In Case 3(e) a stratified model was constructed by randomly distributing 16 permeability values obtained from a log-normal frequency distribution of samples with permeabilities ranging from 1 to 2,000 md. This greater degree of heterogeneity was introduced to determine if it would cause an adverse effect on recovery or its sensitivity to rate. These changes delayed water breakthrough, reduced producing WORs, and increased the recovery relative to the other cases. Both the vertical and horizontal permeability of each layer were randomly distributed in Case 3(f). These changes resulted in earlier water

breakthrough and higher producing WORs, but identical recoveries compared to Case 3(e).

Intercomp's Simonette cases indicated that even though higher production rates caused earlier breakthrough and higher producing WORs, there was a consistent improvement in recovery with production rate for the wide range of rock and fluid properties for which predictions were made.

The results of a radial coning model study for a Sturgeon Lake D-3 well are also shown in Table 6-8 and, being similar to the Simonette study, are not discussed here.

Shell referred to Intercomp's report as a basis for its conclusions that, with few exceptions, increased rates would not detrimentally affect recovery. One exception might be reservoirs subject to gravity segregation where the recovery achieved might be prejudiced by gas coning and where the latter was a function of production rate. For vertical water displacement the only concern would be to ensure full replacement of withdrawals where water coning increased with production rate.

Texaco Exploration

Texaco Exploration referred to the classic Buckley and Leverett paper[27] as a basis for the position that a maximum efficient rate for a pool was defined by conditions under which viscous forces may be neglected. It suggested that the maximum superficial displacement velocity to satisfy this requirement could be determined by the relationship

$$U_t = 0.40\ k_o/\mu_o$$

where: U_t = superficial displacement velocity, $bbl/ft^2/d$
k_o = vertical permeability to oil, darcy
μ_o = oil viscosity, cp

Texaco Exploration submitted that numerical models were the best method for evaluating the effects of production rate on volumetric sweep efficiency. It also suggested that a single maximum fluid rate per well based on initial oil-column thickness at each well would suffice to prevent premature coning and adverse sandwich losses.

6.342 Views of the Board

The velocity of interface movements in the Devonian D-2 and D-3 pools in Alberta have been relatively slow. For example, at a constant production rate of 150,000 bbl/d from the Redwater D-3 pool the oil-water interface would advance some 6 ft/yr at initial conditions or some 10 ft/yr at the current stage of depletion. At this rate of advance, and if the formula proposed by Texaco Exploration is applied, an average vertical permeability to oil of some 1 to 2 md is required for the viscous forces to be negligible compared to that of gravity. The average vertical permeability of the Redwater D-3 Pool is believed to be of this order of magnitude and it is interesting to note that Imperial's analysis of oil-water interface movements indicate a trend of increasing flushing efficiency with cumulative recovery. The Board believes that such a trend is to be expected where there has been no significant change in volumetric sweep efficiency and it concludes that the displacement in Redwater and other high-quality D-3 and D-2 pools in the province is by an efficient gravity-dominated process.

The Board notes that radial coning models were used in most of the simulation studies of vertical displacement processes. These models are adequate for evaluation of coning phenomena but are considered inadequate for evaluation of pool volumetric sweep efficiency or the full effect of reservoir rock heterogeneity on the sensitivity of recovery to production rate. Imperial's study of tight lens systems illustrates the effect of lens properties and position on the terminal oil saturation of the lens. The Board believes that the relatively poor recovery from some of the lower-quality Rundle, D-2, Keg River, and Muskeg pools is due to a low volumetric sweep efficiency caused by severe heterogeneity. In these cases the recovery process is affected more by viscous and capillary forces than by gravity.

The Board agrees with the concept that increased water throughput, where economic and practical, will improve the flushing efficiency; however, it is not prepared to accept that high production rates with attendant water coning will generally result in improved recovery. It believes that the effect of coning on ultimate recovery varies strongly

with pool geometry, local heterogeneities, the type of facilities installed, and corrosion, as well as economic constraints.

There appears to be general acceptance by the participants that gas coning reduces reservoir energy and should therefore be controlled. The Board agrees with that conclusion.

The Board's overall views on the effect of production rate on recovery from immiscible vertical floods are summarized as follows.

General

1. Coning-model studies are recognized as a powerful tool for evaluating the effect of production rate, completion interval, and local heterogeneities on well performance and cone height. Other methods are required to evaluate the effect of production rate on volumetric sweep efficiency and overall pool recovery.

2. The results of coning-model studies are more credible when accompanied by a good match with historical well performance data. Similarly, when models are run at rates requiring a change in facilities the predictions are more credible if supported by studies showing the technical and economic feasibility of high-capacity facilities.

Effect of Individual Well Production Rate on Recovery

3. In any situation increased well rates could reduce pool recovery if they result in gas coning or significant increases in GOR.

4. In a homogeneous or randomly heterogeneous reservoir with favourable rock and fluid properties*, and subject to 3, individual wells in multi-well pools can be operated at capacity provided it is economically and physically feasible to handle and dispose of the water produced.

5. Regarding a homogeneous or randomly heterogeneous reservoir with unfavourable rock and fluid properties, the Board is uncertain about the effect of production rate on recovery and believes caution is warranted in setting individual-well rates.

6. In a heterogeneous reservoir with favourable rock and fluid properties the effect of high individual well rates may be adverse or beneficial to pool recovery depending on circumstances (e.g. well location,

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*See footnotes on page 6-43.

completion interval, pay thickness, etc.) and detailed investigation is required.

7. In a heterogeneous reservoir with unfavourable rock and fluid properties high individual-well rates can adversely affect volumetric sweep efficiency and production rates must be part of the overall depletion plan.

Effect of Pool Production Rate on Recovery

8. In any situation pool recovery may be reduced if increased pool production rate exceeds injection capacity, causes significant variation in gas-oil or water-oil interfaces, or causes a local or regional solution-gas drive to develop.

9. In a homogeneous reservoir with favourable rock and fluid properties, and subject to 3 and 8, the pool production rate may be varied over a wide range without significantly affecting the pool recovery.

10. Regarding a homogeneous reservoir with unfavourable rock and fluid properties the Board is uncertain about the effect of pool production rate on recovery and believes caution is warranted, particularly in pools with wide spacing or few wells.

11. In a randomly heterogeneous reservoir with favourable rock and fluid properties and subject to 3 and 8, pool production rate can be varied over a wide range without significantly affecting oil recovery.

12. Regarding a randomly heterogeneous or a stratified reservoir with unfavourable rock and fluid properties, the Board is uncertain about the effect of production rate on recovery and believes a detailed reservoir study and pool depletion plan are required to ensure maximum recovery.

6.35 Externally-Caused Displacement by a Miscible Fluid

In miscible displacement processes, the absence of an interface or phase boundary between the reservoir oil and the displacing fluids eliminates the residual oil saturation from all but a few isolated or dead-end pore spaces. Thus, the pore-to-pore displacement efficiency approaches 100 per cent. All the methods for attaining miscible fluid displacement involve the injection of a slug of solvent (alcohol, LPG,

refined hydrocarbon, carbon dioxide, natural gas, microemulsion) that is miscible with the reservoir oil, followed by injection of a less costly clean up fluid (water, natural gas, flue gas) which in turn is miscible with the solvent. The various miscible fluid displacements can be broadly classified as miscible slug processes, high pressure gas drives, enriched gas drives, and chemical surfactant processes.

Miscible slug processes using alcohol or LPG for a solvent have been proposed and successfully tested in the laboratory and in the field, however, economic factors have prevented the use of alcohol slugs on a field scale. In the LPG slug process, miscibility is favoured by increased reservoir pressure, low reservoir temperature, light reservoir fluids, and by a displacing or clean up gas which is rich in intermediate hydrocarbons. Special care is required in the design and operation of LPG slug processes to ensure that miscibility is maintained and that a good volumetric sweep of the reservoir is achieved. The slug must be appropriately sized to allow for dispersion and diffusion losses as it travels through the reservoir. The adverse mobility between the solvent and the reservoir oil and between the displacing gas and the solvent can result in viscous fingering and a reduced volumetric sweep efficiency. In vertical floods, gravity helps to dampen fingering and stable interfaces may be maintained by adjusting the rate of interface advance. In horizontal systems reservoir stratification and gravity over-ride may require the alternate injection of gas and water to control the instability at the displacement front.

A high pressure gas drive process can result in miscible displacement provided the reservoir oil is sufficiently volatile. In this process a lean gas is injected at high pressure and after repeated contacts with fresh reservoir oil sufficient intermediate fractions are vapourized into the gas to cause a miscible displacement. The cost of high pressure gas and the requirement that the reservoir oil be rich in intermediates limit the general application of this process.

In an enriched gas drive the injected gas contains large quantities of intermediates which are condensed into the reservoir oil. After repeated contact with fresh injected gas, sufficient intermediates are condensed into the oil and miscibility is achieved. The high cost and

scarity of enriched gas usually requires that a dry gas be used to displace an appropriately sized slug of enriched gas.

In chemical surfactant processes the interfacial tension between oil and water is reduced to such low levels that a miscible type of displacement is possible. In some early processes the surfactant was dissolved in the injected water, but these were relatively unsuccessful because of adsorption of the surfactant on reservoir rock. Microemulsion flooding has mitigated the adsorption problem and it is currently the most promising chemical surfactant process. Microemulsions are surfactant stabilized dispersions of oil and water. These dispersions are capable of "solubilizing" fluid without losing their stability. However, since their viscosity is a strong function of their composition, a mobility buffer is usually required to minimize viscous fingering and to ensure the integrity of the microemulsion slug. The process involves the injection of a microemulsion slug of 3 to 10 per cent pore volume followed by a mobility buffer (aqueous polymer solution) followed by injection water.

All miscible displacement processes are susceptible to mobility control problems and the primary effect of increased production rate is to aggravate these problems.

6.351 Views of the Participants

None of the participants presented any quantitative analyses of the sensitivity of miscible displacement processes to production rate. A few acknowledged that these processes require special consideration or that they are usually more rate sensitive than other recovery mechanisms.

6.352 Views of the Board

In Report OGCB 65-3, the Board considered that recovery from miscible displacement processes was inherently more sensitive to production rate than the recovery from other recovery mechanisms. The Board continues to hold this view, particularly in those cases when there are significant compositional effects and where mobility control problems exist.

The Board also notes that while numerical simulation studies have increased the knowledge of the sensitivity of all recovery processes to production rate, miscible displacement processes are probably the most difficult for which to match predictions with field performance. It is the Board's understanding that extreme care must be taken to control numerical dispersion in models of miscible displacement processes.

6.4 Development and Operating Practices in Alberta

The manner in which an oil field is developed and the manner in which wells are completed and operated can affect oil recovery and its sensitivity to production rate. The practices having the most important affect are:

(a) well location and spacing,
(b) well completions, workovers, and fluid lifting facilities,
(c) surface handling and processing facilities,
(d) distribution and scheduling of production and injection, and
(e) well and pool abandonment.

Comments are given below on current practice in Alberta and its relation both to recovery and to sensitivity of recovery to production rate. The participants' views are presented followed by those of the Board.

6.41 Well Location and Spacing

Spacing regulations in Alberta are intended to achieve an optimum well density (i.e. just enough wells to permit effective depletion of the reservoir but avoiding the economic waste of drilling unnecessary wells) and to permit equitable production among pool owners. The approach adopted in Alberta is based largely on avoiding the inefficient and inequitable drainage resulting from overly close and irregular spacing which occurred in the early stages of the industry. The change from close spacing to wide spacing evolved between the late 1940's and the early 1960's.

In Alberta the normal size of an oil well DSU is 160 acres, but variations ranging from 10 acres, in some heavy-oil pools, up to 640 acres (which is also the normal spacing in gas pools) have been permitted. Generally, closer spacing is considered necessary and is authorized as reservoir rock and fluid properties become less favourable.

The location of a well within a DSU is confined to a central target area, largely to promote equitable drainage but also to maintain a systematic distribution of wells. One disadvantage of a systematic distribution is that it does not permit wells to be located entirely on the basis of geological knowledge of the pool. In cases where this is critically disadvantageous, special spacing units or target areas are permitted, provided that correlative rights are not violated.

In a practical situation, the determination of proper spacing and well location is influenced by evolving knowledge of the pool. The normal 160-acre spacing applies unless or until knowledge of the pool's size, shape, rock and fluid properties, recovery process and production characteristics indicate that a different spacing would be appropriate. As development and depletion proceed, local irregularities and variations in the shape and character of the pool become evident. These include lobes, saddles, facies changes, faults, and directional permeability, some at which are not evident until depletion is well advanced.

Infill drilling may be warranted as a result of a significant increase in market demand requiring greater productive capacity, a change in the method of prorating to market demand, or implementation of enhanced recovery operations. Infill drilling is usually done on a selective basis having regard for the knowledge acquired from previous drilling and production operations in the pool.

Well spacing has a minimal effect on recovery at very close spacing but the effect becomes increasingly significant at wider spacing and as heterogeneity increases. Close spacing provides detailed knowledge of the pool and permits considerable flexibility in replacing problem wells and dealing with reservoir heterogeneities. Under wide spacing, pool knowledge is limited, and if the practical drainage limit of individual wells is exceeded, significant recovery losses will occur.

A uniform distribution of wells is beneficial for the initial development of an oil pool where there is variability in mineral ownership. It provides a balance between correlative rights and pool development during the period when the pool's characteristics and extent are determined. In relatively uniform pools this permits uniform drainage and high sweep efficiencies in pattern floods. In non-uniform pools subsequent drilling can be carried out taking account of local variations in reservoir properties and characteristics. In oil pools where there is common ownership, well spacing and location should be based on a consideration of the reservoir properties, ultimate recovery and economics of the overall pool.

Well spacing may affect the relationship of production rate to recovery in several ways. Higher allowables may lead to closer spacing, either initially or through subsequent infill drilling, and this may provide a better knowledge of the pool which may be important to ultimate recovery. On the other hand, if closely spaced wells are concentrated in prolific areas the exaggeration of differential depletion may lead to loss of recovery from marginal areas. Also where pool-wide coning is detrimental to recovery the decreased drawdown resulting from more wells producing the same total allowable would improve recovery. Finally, where coning or wellbore problems result in inadequate depletion at a specific wellbore and where neighbouring wells are too far away to serve as replacements, there will be a loss of recovery. In all cases, however, the potential gain from additional wells must be weighed against the cost.

6.42 Well Completions, Workovers, and Fluid Lifting Facilities

Most oil wells drilled in Alberta in the late 1940's and early 1950's were completed with 7-inch diameter production casing. In subsequent development of the Cardium, Beaverhill Lake, and Gilwood formations wells were completed with 4½- and 5½-inch diameter casing, while in development of the Keg River during the latter part of the 1960's wells were completed with 7-inch diameter casing. In general the use of large-diameter casing permits a higher rate of production and facilitates workovers and multizone completions but adds considerably to the initial well cost.

A common practice in both the Leduc and Keg River formations was to set production casing to the top of the reef to minimize problems with lost circulation. Well completions were either open-hole or with liners set in the bottom of the casing. Open-hole completions are suitable for moderate production rates in thick reservoirs with favourable rock and fluid properties. In cases where gas-oil or water-oil interfaces are present in the well the tubing is suspended within the oil column and any significant drawdown is quickly evidenced by production of water or excess gas. Liner completions with selective perforations tend to sustain oil productivity in coning situations, and also provide better control over the location of withdrawals from or injection into the reservoir.

The practice in the Cardium, Beaverhill Lake, and Gilwood formations was to case through the productive section and selectively perforate. Although productive capacity is usually enhanced by selective completion and stimulation, this practice does not assure high recovery. Some workovers to complete new zones may be necessary to ensure maximum recovery from stratified reservoirs. It may be preferable to have full face completion in injection wells and those producing wells where it would be easy to selectively plug back or isolate those zones which have broken through to the displacing fluid. The ideal situation, from a recovery view point, would be to assure that each zone of each well is produced to its limiting GOR, WOR or oil rate. This would tend to be the case where an active production logging and recompletion program is part of the operating practice.

Workovers that may be required after the initial completion include recompletions to increase productivity or to control the ingress of water or gas, and the servicing or repair of mechanical equipment such as pumps, tubing, and packers. Recompletions to control water or excess gas usually involve reducing the production interval by such methods as installing liners in open-hole completions, plugging back the lower portion of a well, or isolating a portion of a wellbore by using packers or by squeezing cement into existing perforations. The success ratio of these types of recompletions is probably no more than 50 per cent in the typical thin-pay Alberta pool. The low success is usually attributed

to the difficulty of achieving a good cement bond between the casing and the wellbore. Extensive fracturing of the wellbore aggravates recompletion problems while in certain cases impermeable layers are advantageous.

Sucker-rod pumps are by far the most common type of artificial lift device used in Alberta. Other types such as subsurface electric centrifugal pumps, subsurface hydraulic pumps, and gas lift systems are in limited use throughout the province. Each type has its own peculiar advantages and disadvantages. In particular the latter two require compression facilities to develop high pressure power fluid, either oil or gas, and an additional network of lines to deliver the fluid to the producing wells.

The type of completion and lifting practices limit both the minimum and maximum well production rates. In all cases the minimum rate results from the need for operation of the well to be economic, and in some cases from the inability of the equipment to function properly below a certain rate. Besides being the physical limit of the particular downhole installation, the maximum rate may also result from it not being economically or physically possible to upgrade existing equipment.

Both the minimum and maximum rates may affect ultimate recovery. The minimum is important where gas or water intrusion is mitigated by a reduction in rate and by use of selective completions. Also, when solution gas drive reservoirs approach depletion, it is desirable to be able to operate wells economically at the low rates attending the decline of pressure. The maximum is important where intrusion is handled by increasing the rate of total fluid production so that larger volumes of gas or water may be cycled economically. The cost of installation and operation per unit of rate capacity usually decreases as the capacity level increases. In gas-cap and water drive reservoirs, it is frequently desirable to minimize coning by reducing rates and using selective perforations in the early stages when gas or water intrusion is moderate or affects only a few wells in a pool. Later it may be feasible to convert to high rate cycling of the gas or water. Flood schemes frequently require the flexibility of both high and low production rates in order to control the flood front as its course becomes apparent. This applies especially in horizontal floods in heterogeneous pools where the course

of the flood may be significantly distorted in local areas. In addition, there should be control of injection into and production from individual zones within grossly stratified reservoirs.

In vertical solvent floods the solvent bank must be properly distributed at the outset and maintained intact throughout the life of the scheme. Because the bank tends to diffuse and disperse, and because bank integrity is critical, it is important to control production rate and to have flexibility to deal with unexpected performance as it occurs. Control of coning at production wells is also critical because relatively little production of solvent can be tolerated until the latter stages of the flood.

In general, the greater the flexibility of operation throughout the producing life, the greater the opportunity to achieve maximum recovery. Again, the cost of providing that flexibility must be balanced by the value of the gain in recovery. At the terminal stages of depletion, the minimized cost of operation, which in many cases is associated with high rates, ultimately becomes the factor that leads to maximum crude oil recovery.

6.43 Surface Handling and Processing Facilities

Surface handling and processing facilities may include flowlines, batteries (facilities for separation and measurement of oil, gas, and water), gas gathering and processing facilities, water disposal systems and fluid injection systems. A simple system might involve only a flowline, possibly a separator or treater and a storage tank. However, most production systems are considerably more complex, expecially those for enhanced recovery schemes in larger pools. Where ownership or agreements permit, it is possible to incorporate many wells into a central battery thereby benefitting from economies of scale. In this case wells are tested at satellite batteries distributed throughout the field.

A major part of Alberta's oil production comes from pools with enhanced recovery schemes. Each scheme requires the development of a suitable supply of displacing fluid and facilities for its delivery to injection wells. In the case of water-flood the production stream will

contain an increasing fraction of water as the scheme progresses. This water must be cycled or otherwise disposed of in a satisfactory manner. Regulations prohibit surface disposal of any significant volume of water.

Gas conservation orders requiring the gathering of solution gas are in effect in many oil fields throughout the province. These orders require that gas from low-pressure units such as separators, treaters, and tanks be gathered, compressed, and processed as necessary to achieve conservation objectives. The capacity of gas gathering or processing facilities may impose either a minimum or maximum constraint on production rates.

Surface handling and processing facilities are simply an extension of the production system beyond the well completion and fluid lifting devices discussed earlier, and the effect on recovery is similar. Reduction of operating cost and increased flexibility lead to higher recovery. Centralization of field facilities results in lower operating costs but may also diminish the flexibility of operations and restrict the production rates of some wells. In cases where displacing fluid supply and injection, water disposal, and gas conservation operations are integrated into the system, flexibility is further diminished because of the limits of each component operation. In most cases it is physically possible to improve flexibility but uneconomic beyond a certain point. The design of a production system should achieve a balance between economic efficiency and flexibility of operation.

The effect of any part or all of the production system on the sensitivity of oil recovery to production rate results through its interrelationship with economics. It is generally required that any upgrading of component facilities be profitable on a present-worth basis. Because present-worth profitability is affected more by short-term oil production rates than by long term oil recovery, any modifications must be accompanied by a short-term sustenance of, or increase in, rates. The practicalities of the situation usually lead an operator to favor maximum current rates with less consideration of whether these may bear seriously on future recovery. The Board, on the other hand, must be concerned with the longer term.

6.44 Distribution and Scheduling of Production and Injection

Distribution and scheduling of production in Alberta has been affected by regulations which provide for allocation of the market demand among pools and wells, protection of correlative rights among owners, and practices designed to increase ultimate recovery. Beyond these constraints the normal practice is to economize in the number and type of wells being operated.

Since the commencement of proration in Alberta in 1950, production regulations have allowed some form of transferral or aggregation of allowables within enhanced recovery projects and in areas of common ownership. Current regulations permit certain tracts of common ownership to be grouped into PSUs for which the aggregate allowable is produced from one well only. PSUs in turn can be grouped in blocks where each component PSU is required to demonstrate its continued allowable entitlement by producing at least its minimum allowance for each period of three consecutive months.

Such regulations provide for economy of operation and often result in intermittent operation where the monthly allowable of the PSU is produced in a few days and the well shut-in for the remainder of the month. This is also possible in blocks where the minimum allowances of PSUs are small compared to the productive capacity and thus may be produced rather quickly. On the other hand, it is desirable in certain cases to maintain continuous production, as for example, in weakly flowing wells or wells with sand production which would settle out and block the bottom of the well if production were stopped.

Some additional rate restrictions are imposed on control wells at the borders of blocks for the protection of correlative rights. These wells are normally produced to the limit of the restrictions.

GOR and WOR penalties are applied to inhibit the waste of reservoir energy. It is common practice to take advantage of PSU and block regulations to avoid or minimize water and excess gas production.

Enhanced recovery schemes under project status generally have more flexibility in the operation of individual production and injection wells than do most primary depletion operations. There are generally no regulatory restrictions on individual well production rates

except in the case of control wells at lease boundaries. Sometimes minimum pressure or producing GOR level are specified for producing wells and maximum pressures for injection wells. Complete replacement of reservoir withdrawals is generally required only on an overall project and monthly balance basis. Since produced water is normally returned to the reservoir, WOR penalties are generally not applicable although GOR penalties frequently are. Performance surveillance is relied upon to ascertain the need for other controls.

The mode of operating individual production and injection wells depends on the design and performance of the particular enhanced recovery scheme. In line-drive or peripheral water-floods, the wells adjacent to the flood-front are generally produced to the limit of capacity but more distant ones only to the extent necessary to achieve production targets, or to prevent undue pressure differentials. Production of individual wells at the flood-front is usually controlled to maintain a relatively uniform frontal advance. Injection locations may be moved forward as the front progresses to reduce the pressure drop between injectors and producers.

In pattern water-floods all wells are usually operated. Attempts are often made to achieve a uniform rate of flood-front advance across patterns, between adjacent patterns, and to a certain extent across entire projects. As mentioned, proper initial distribution of the solvent bank in vertical solvent floods and subsequent maintenance of the integrity of the bank is of critical importance. Production and injection should be scheduled to achieve this.

Most aspects of the distribution and scheduling of production and injection can affect ultimate recovery. The tendency to take production from only the high capacity wells may result in some areas not being drained effectively. In more heterogeneous reservoirs it is more likely that some portions of the reservoir will not be fully depleted by widely-spaced wells. In cases where coning leads to a loss of recovery this effect will be aggravated by any practice, such as intermittent production, which causes increased daily production rate. In enhanced recovery processes the control of the flood-front to ensure maximum sweep of the reservoir in accordance with the design of the particular scheme, is considered of paramount importance.

6.45 Well and Pool Abandonment

A well is normally abandoned when the revenue from its oil and gas production falls below its operating cost. There is some variance in opinion as to what constitutes the operating cost for this purpose, since a well is usually only a part of the overall production system. The rigorous evaluation of multi-rate performance predictions are further complicated by the need for costs to be classified as either fixed or variable with fluid production rate.

The abandonment phase of most pools extends over a considerable time period because of differences among individual wells. In line-drive and peripheral water-floods, well abandonments occur over most of the life of the flood. In solvent-floods, gas-floods, gas-cap drives and solution gas drives with gravity segregation, there will usually be a blowdown phase during which further efforts at oil recovery are discontinued and the wells are operated as gas wells. In such cases and in solution gas drives in pools with low permeability or high solution GORs the value of produced gas may exceed that of the oil.

The cost of lifting, separating and disposing of produced water in natural depletion operations and the additional cost of water supply and injection in water-floods is often the major operating cost. The economic incentive for installing higher-capacity and lower unit cost facilities diminishes with pool depletion. On the other hand, installation of high-capacity facilities at an early stage may result in a long period of over-capacity and, since all facilities have a finite life, require replacement at some later time when it cannot be justified.

The operating costs of the first few wells to approach the economic limit may be partially absorbed in the overall costs of the production system. As more wells are abandoned there is a tendency to pare operating costs and avoid further significant capital expenditures. This final stage of operation of a well or pool is sometimes called "stripping". The decision to abandon is often made because a significant expenditure is required for well servicing or equipment replacement.

When few wells remain in a pool and the performance of all wells has deteriorated, at some point the operation becomes uneconomic and

the remaining wells are abandoned.

The point at which individual wells and pools are abandoned obviously affects ultimate recovery. The economic limit is determined more by the installed facilities than by the final operating practices. Greater installed capacities usually result in lower final operating costs (per unit of capacity) which in turn result in higher ultimate recovery.

The relationship of abandonment to rate and recovery follows from the above. There will be an improvement in recovery to the extent that higher early rates result in greater capacity being in place at the abandonment stage and to the extent that this greater capacity is more efficient economically. Where water or gas production are not excessive, the important factor is the ability to operate economically at very low rates.

The Board reviews each proposed oil well abandonment for adequacy of depletion, use of the well for other purposes such as water injection or disposal or for tertiary recovery, and for potential of other zones in the well.

6.46 Views of the Participants

Board Staff

While the Board staff did not evaluate the specific effects that development and operating practices could have on recovery or its sensitivity to production rate, it stated that valid conclusions could not be drawn about these matters independent of knowledge as to field conditions or practices. It considered that practices which affect the performance of individual wells would also affect pool performance and recovery.

The Board staff noted that there were situations where it would be most profitable to produce only the better wells, although it would still be profitable to take the production more uniformly from all capable wells. It contended that such an operating practice, which it considered to be high-grading, would result in rapid depletion of prolific zones at the cost of otherwise recoverable oil from the lower-permeability portions of the reservoir.

Amoco

Amoco submitted that, in general, most pattern floods should be operated under conditions which encourage equal reserve depletion rates. It stated that considerable operating flexibility was required, particularly in the South Swan Hills solvent-flood where some 20 patterns must be kept close to the same stage of depletion in order to inject fluids in the proper sequence through the high pressure injection system. It pointed out that permeability and porosity trends could influence the degree of adherence to the equal reserve depletion rule.

Ashland

Ashland proposed that for horizontal water-floods in sandstone reservoirs maximum well-head injection pressures be prescribed for each reservoir, but no restrictions be placed on rate. It also proposed that full replacement of voidage on a monthly basis be required. It stated that such controls would provide a suitable method of satisfying both conservation and economic constraints.

Ashland stated if initial rates were restricted it may not be economical to change facilities later to increase rates in attempts to improve ultimate recovery.

For wells subject to pattern water-flood in the north unit of the Pembina Keystone Belly River B Pool, Ashland's data indicated fixed costs equivalent to an oil production rate of 9.64 bbl/d and variable costs of 0.015 bbl of oil for each barrel of produced fluid.

Great Plains

Most of the studies made for Great Plains by Intercomp assumed full voidage replacement around the outer periphery of the model. Intercomp studied the productivity and drawdown effects at producing wells but made no studies of the constraints imposed by limitations of production or injection facilities.

During testimony, Intercomp agreed that changes in well pattern and completion intervals could significantly affect recovery, but it held that a change in rate did not adversely affect recovery under otherwise constant conditions. Intercomp also agreed that operational practices and constraints could have an important effect on the ultimate recovery.

Intercomp's study did not provide any specific data or analysis of costs affecting the economic limit. It used an abandonment rate of 5 bbl/d of oil for its example well from the Swan Hills field. The reservoir model predictions for wells in the Rainbow field were arbitrarily terminated at 60,000 days. An abandonment rate of 15 bbl/d of oil was used for the heavy-oil example well in the Countess field. Regarding analyses of the performance of a well in the Simonette field, Intercomp stated that the fixed operating costs generally exceeded variable costs and therefore the economic limit was considered more a function of the oil rate than the WOR. This view was also submitted by Shell. An abandonment rate of 5 bbl/d of oil was used by Intercomp in its several predictions for Belly River wells.

Gulf

Gulf stated that ultimate recovery could be endangered where differential displacement tended to prevent further recovery after breakthrough. It suggested that comprehensive model studies were required to determine the best distribution of production and injection.

Home

Home stated that during periods of high market demand for oil, there is an economic incentive to rework wells, drill infill wells, gather extensive reservoir data, and monitor flow performance of injectors and producers, all of which lead to increased recovery. It stated that any system of regulation which unnecessarily restricted production rate would lead to reduced ultimate oil recovery.

Home's data indicated that the economic limit for a typical well in the Swan Hills field could be approximated by an oil production rate of some 16 bbl/d plus 0.04 bbl of oil for each barrel of produced fluid.

Husky

Husky stated that individual well rates in heavy-gravity oil pools are currently limited more by wellbore and operational problems than by the ability of the reservoir to produce. Sand produced continuously with oil causes problems, especially at low production rates or upon shutdown when the sand drops out of suspension and accumulates in the wellbore. Another operational problem is the slow rate of rod fall due to the high viscosity of the oil.

Imperial

Imperial performed studies on several aspects of field development and operating practices. It used actual cost data from the Redwater and Judy Creek fields for calculation of economic limits. The data illustrated a significant variation in energy and maintenance costs for different types of artificial lift installations. An approximation of Imperial's cost data for Redwater wells shows fixed costs corresponding to an oil production rate of about 5 bbl/d and variable costs of about 0.04 bbl of oil for each barrel of produced fluid. A similar approximation of Imperial's cost data for Judy Creek wells indicated fixed costs corresponding to 17 bbl/d of oil and variable costs of 0.033 bbl of oil for each barrel of produced fluid. The latter agreed well with the economic limits suggested by Home for the Swan Hills field.

Imperial stated there was a definite risk that lack of economic incentive to install facilities later in the life of a reservoir would result in a loss of recovery.

It said there was a need for overall voidage balancing to maintain the desired recovery mechanism, but recommended full flexibility of injection and production schedules. Flexibility was considered necessary in order to alter production operations as appropriate when breakthrough occurred.

Imperial performed numerical simulation studies to investigate the effects of production scheduling and selective withdrawal patterns on ultimate recovery. Two different models were used. Each had two wells, one in a low-permeability region and the other in a high-permeability region. The high- and low-permeability regions contained equal oil volumes. Five production schedules were applied:

(1) a constant oil production rate equal for each of the two wells,

(2) production of the high-capacity well only, until its productivity fell below the target rate,

(3) a constant total fluid rate equal for each well,

(4) production of the high-capacity well at ten times the rate of the low-capacity well,

(5) production of the high-capacity well at fifteen times the rate of the low-capacity well.

The vertical cross-sectional model was taken to be representative of a bottom-water drive. The 100 ft thick oil zone was divided into 10 equal layers, the 100 ft thick aquifer into 3 layers, and the 5940 ft length into 18 equally spaced blocks. The rock and fluid properties and the economic limits were the same as those used in Imperial's Leduc coning model studies. The results of this study are summarized in Table 6-9. The final recovery was quite insensitive to the production schedule. The highest recovery was achieved under rate schedule 2 (i.e. selective withdrawals).

The areal model was 5278 ft long, 2000 ft wide, and 100 ft thick. Each grid block was 377 ft long, 200 ft wide, and 100 ft thick. A horizontal water-flood was simulated by water injection across one end of the model with the two producing wells located in central grid blocks at the other end of the model. The rock and fluid properties and the economic limits were the same as those used in Imperial's Beaverhill Lake model studies. The results for this model are also summarized in Table 6-9. Again the final recovery was not very sensitive to the production schedule, with three schedules resulting in the same oil recovery. Imperial concluded that selective withdrawal patterns for the bottom-water drive and horizontal water-flood cases considered tended to result in increased rather than decreased ultimate recovery. It was also concluded that individual pools subject to a common mechanism should not be subdivided into separate MRUs as proposed by the Board staff.

6.47 Views of the Board

The Board believes that the effects of development and operating practices on oil recovery and its sensitivity to production rate are strongly affected by the ability to cope with coning phenomena or the breakthrough of displacing fluids to producing wells. Generally, the practices which permit the greatest flexibility of operation result in the highest recovery and minimize any adverse effect or maximize any beneficial effect of rate on recovery. Consider, for example, the

TABLE 6-9

SUMMARY OF THE RESULTS FROM IMPERIAL'S MODEL STUDIES OF SELECTIVE WITHDRAWAL PATTERNS

Case No.	Physical Properties: Rock	Fluid	Rock Fluid	Fluid Rate Schedule	Recovery At Econ. Limit, Per cent	Performance Characteristics: Recovery At Breakthrough, Per cent	Cumulative WOR, bbl/bbl	Producing Life, Years
1	2-Well Cross-Sectional Model							
	Well A							
	k_h = 5000 md	$\mu_o \simeq$ 2.6 cp	P_c = 50 → -50[†]	1*	61.5	28.3	6.50	48.3
	k_v = 10 md	μ_w = 0.9 cp	S_{wi} = 0.25	2	61.6	18.3	6.60	48.3
	ϕ = 0.0653	$B_o \simeq$ 1.125	S_{or} = 0.25	3	60.7	20.3	4.32	63.4
	Well B			4	61.1	18.5	8.26	59.2
	k_h = 500 md			5	61.1	17.6	8.79	58.7
	k_v = 1 md							
	ϕ = 0.0653							
2	2-Well Areal Model							
	Well A							
	$k_x = k_y$ = 1000 md	$\mu_o \simeq$ 0.32 cp	P_c = 50 → -50[††]	1**	66.0	29.7	1.24	21.2
	ϕ = 0.09	μ_w = 0.44 cp	S_{wi} = 0.08	2	66.0	23.4	1.19	18.7
	Well B	$B_o \simeq$ 1.65	S_{or} = 0.25	3	64.3	29.7	0.76	24.1
	$k_x = k_y$ = 10 md			4	66.0	21.3	1.56	20.2
	ϕ = 0.09							

*Data On Fluid Rate Schedule and Economic Limit For Case No. 1

Fluid Rate Schedule	Well A: Initial Fluid Rate, bbl/d	Maximum Fluid Rate, bbl/d	Final Oil Rate, bbl/d	Final WOR, bbl/bbl	Well B: Initial Fluid Rate, bbl/d	Maximum Fluid Rate, bbl/d	Final Oil Rate, bbl/d	Final WOR, bbl/bbl
1	1000	2000	14	142	1000	2000	14	142
2	2000	2000	14	142	0	2000	14	142
3	1000	1000	10	99	1000	1000	10	99
4	10000	10000	47	212	1000	1000	10	99
5	15000	15000	68	220	1000	1000	10	99

**Data On Fluid Rate Schedule and Economic Limit For Case No. 2

Fluid Rate Schedule	Well A: Initial Fluid Rate, bbl/d	Maximum Fluid Rate, bbl/d	Final Oil Rate, bbl/d	Final WOR, bbl/bbl	Well B: Initial Fluid Rate, bbl/d	Maximum Fluid Rate, bbl/d	Final Oil Rate, bbl/d	Final WOR, bbl/bbl
1	800	1600	60	26	800	1600	60	26
2	1600	1600	60	26	0	1600	60	26
3	800	800	46	16	800	800	46	16
4	800	8000	166	47	800	800	46	16

[†]Maximum oil-water capillary pressure 50 psi decreasing to 0 psi at $S_w \simeq 0.56$ and to -50 psi at $S_w = 0.75$

[††]Maximum oil-water capillary pressure 50 psi decreasing to 0 psi at $S_w \simeq 0.36$ and to -50 psi at $S_w = 0.75$

differences in flexibility of the development in the Redwater D-3 and Simonette D-3 Pools. Redwater was developed on 40-acre spacing and most wells were completed with 7-inch casing. The pool is relatively shallow and it is common practice to run high-volume pumps and dispose of large quantities of coned water. On the other hand, Simonette is very deep, was developed on 160 acre or larger spacing and most wells were completed with 5½-inch casing. Although some Simonette wells have high productivity indices, it has not been common practice to produce large quantities of water because of limitations of artificial lift equipment and corrosion problems. Thus, while widely ranging individual-well rates can be economically achieved in Redwater, only a comparatively narrow range is physically or economically sustainable in Simonette.

Operating flexibility is also affected by surface handling and treating facilities. For example, the field-wide water disposal system and the multiplicity of batteries in Redwater permit much more flexibility in production rates than some of the multi-pool gathering facilities and satellite testing facilities common in the Zama-Virgo area. While a wide range of water production rates can be handled economically in Redwater, only a comparatively narrow range is practical for optimizing pool recoveries in the Zama-Virgo area.

With respect to Imperial's model studies of selective withdrawal patterns, the Board acknowledges that production scheduling had little effect on ultimate recovery for the cases studied. The Board is not convinced, however, that this is generally true and it is not prepared to extrapolate the conclusions to heterogeneous and low-productivity reservoirs.

The Board's views are summarized as follows:

1. The Board believes that the capacity and flexibility of the installed facilities (including production and injection wells) must be considered when assessing the effect of production rate on recovery. While it recognizes that many facilities can be modified and infill or replacement wells drilled to relieve a constraint or otherwise help to ensure or improve ultimate recovery, these modifications occur only where economically justified and consequently are difficult to predict. The Board does not believe it should anticipate modified facilities, but

rather it should assess the situation on the basis of the installed or planned facilities.

2. The practice of wide initial spacing is sound, particularly in a prorated market. In an unrestricted market, however, infill drilling and closer well spacing may be economically warranted and in some cases required to maintain productive capacity. In stratified and highly heterogeneous reservoirs each well tends to assure or improve recovery by its oil production and by the additional reservoir data it provides. The Board concludes that, within economic limits, close well spacing gives a measure of flexibility which helps to minimize any adverse effects and to maximize any favourable effects of production rate on recovery.

3. In stratified reservoirs where facilities or other factors limit the flexibility to vary individual well rates and handle displacing fluids, particular attention must be given to controlling injection and production intervals to minimize the adverse effects of stratification.

4. The Board believes that, in the absence of a thoroughly engineered depletion plan which indicates the contrary, it is desirable to maintain relatively uniform flood-fronts in line-drives and pattern-floods and relatively level interfaces in vertical displacement processes.

5. Operating costs are the all-important consideration when estimating the economic limit for different production rates. There is usually some economy of scale associated with surface handling and processing facilities, but the Board is not convinced that similar economies of scale apply to bottom-hole pump installations, particularly where small-diameter casing is installed. Thus multi-rate performance predictions should be supported by a study of the technical and economic practicability of sustaining the high rates to at least the equivalent recovery level predicted for lower rates.

7 THE NEED FOR SURVEILLANCE OF PRODUCTION RATE

In section 6, the Board concluded that under some conditions production rate can affect ultimate recovery. In this section it reviews the need for general surveillance of production rate and the particular need for the examination of the significance of historical and current production rates to identify those wells or pools where production rates are at levels suspected or known to affect ultimate recovery. It does not include a review of the need for actual regulation of production rate.

It became evident during the course of the hearing that "surveillance of production rate" has different meanings to various individuals or groups. It meant superficial review of production rates to some, comparison of pool or well rates with those from the PRL formula to others, and a few thought that, in the event of adverse performance, it included the regulation of rates and the application of penalty factors. Thus some clarification of past and present surveillance practices would seem appropriate prior to assessing the need for surveillance of production rate.

7.1 The Need for Surveillance of Individual Well Production Rate

As discussed in section 3, the Board has required that detailed information be reported to it on such matters as the physical properties of reservoir rocks and fluids, individual well completion and workover data, and monthly well production data. This information is currently stored in computer files and is available for surveillance purposes.

In addition to the surveillance required because of equity matters (control well rates, proration over production and under production status) and the surveillance required as a consequence of Board Orders and Approvals (voidage replacement, minimum reservoir pressure, maximum GORs, etc.), the Board has also performed some surveillance of the effect of individual well rates on performance characteristics and on ultimate recovery. Until the higher production rates of 1973 and 1974 this surveillance was primarily directed toward ensuring that enhanced recovery schemes were initiated

wherever practical. From 1973 until the present time this surveillance has been directed more toward ensuring that pattern or pool voidage replacement was in balance with increased individual well production rates. While there have been a variety of factors contributing to need for surveillance of individual well production rate, the Board believes it should be established whether there is a special need for the surveillance of the effect of individual well production rate on crude oil recovery.

7.11 Views of the Participants

Board Staff

Since the Board staff contended there could be an adverse effect of high production rate on ultimate recovery, it implied there was a need for surveillance of individual well production rate and performance characteristics. Its position was that unusual or adverse GOR and WOR performance could be masked in the averages for larger production entities such as blocks, projects or pools.

Industry Participants

Although the view of the majority of industry representatives was that high individual well production rates did not adversely affect ultimate recovery, there was general agreement on the need for surveillance of individual well production rate and performance characteristics. There was no agreement as to what this surveillance should involve and several submitted that the factors requiring surveillance would vary with the particular well, pool and recovery mechanism.

Gulf submitted that since pool performance must be the sum of the rate-time performances of the individual wells therein, analysis of the producing history of each well provides another route to evaluation of reservoir performance. In keeping with the importance of individual well performance it proposed a new formula approach for calculating maximum per-well production rates.

Husky stated that prolonged and excessive coning could result in reduced recovery. It supported the use of an MRL formula to help identify wells where coning might be a problem.

Imperial questioned whether individual well surveillance was required so long as there was sufficient economic incentive remaining to support the replacement of wells whose loss, without replacement, could result in reduction in ultimate recovery from the pool. Imperial stated that unique conditions would be required before individual well rates could reduce pool recovery.

A few participants supported the surveillance of control well rates particularly when adverse performance indicated there was a need.

7.12 Views of the Board

The Board believes that as declining productivity, market conditions, and the proration plan permit well production rates to increase towards their physical capacities, as presumably they again will, it will become important not only to maintain the present system of surveillance of well production or injection rates and other data including a comparison of present GOR, WOR and pressure trends with previous trends in the same well or other similar wells, but to supplement these with special studies to appraise the potential for coning and fluid over-ride, and to identify the occurrence of irregular advance of displacing fluid interface, the development of adverse relative permeability and the like.

7.2 The Need for Surveillance of Pool Production Rate

The Board has maintained surveillance of pool production rates and performance characteristics for many of the reasons it undertook surveillance of individual well production rates. This has included the comparison of pool rate with the PRL formula and the totalling, averaging and analyzing of the data from individual wells in pools. The Board staff has performed independent studies on some pools and the Board, in the course of keeping its records, has provided various data and publications for its own and general use including pool performance charts and reservoir pressure summaries. Several publications provide oil, gas and water production statistics, and reserve data.

In addition to the compilation of individual well and pool total data, the Board's historical surveillance of pool performance characteristics has included interpretation and study of oil-water and gas-oil interface movements. It has also included tracking the breakthrough of any injected fluids.

The surveillance of pool performance is usually more complicated than individual well performance since it includes the latter as well as interpreting and analyzing regional variations in recovery mechanism, reservoir pressure, voidage replacement ratios, etc.

7.21 Views of the Participants

Board Staff

The Board staff accepted that there was a need for pool surveillance and stated further that the onus was on the operator to demonstrate that prevailing pool rate or depletion plan would not be detrimental to ultimate recovery.

Industry Participants

Alminex stated there was a need for surveillance of pool production rate and implied that a general PRL formula could be used to decide when further pool study or evaluation is warranted. Amoco, Aquitaine, CPA, Mobil and PanCanadian expressed similar views.

The position of Alminex, Ashland, Dome, Hudson's Bay, Imperial, IPAC, Petrofina, Shell and Texaco Exploration was that surveillance of pool production rate may be necessary but there is no single universal formula for calculating reference rates.

Gulf considered there was a need for surveillance and proposed that the aggregate of its formula method for maximum per-well rate serve as a guide to the maximum pool production rate. Like many other participants it also favoured the proposal that the Board encourage or require pool MER studies.

Home expressed the opinion that the Board's conservation objectives could be achieved by surveillance by the Board followed by necessary actions. Surveillance, in Home's view, meant a review or study to define

pools or portions of pools where loss of recovery might occur in the absence of rate restrictions.

Chevron and Imperial questioned whether a formula approach was required for surveillance. Chevron suggested that engineering judgement along with the normal information requirements of the Board would suffice.

Atlantic Richfield, Petrofina and Union stated that, in the event of adverse performance, the PRL could serve as a reference level for the application of penalty factors.

7.22 Views of the Board

The Board agrees with the opinion expressed by many that there continues to be a need for surveillance of pool production rate and pool performance to determine, among other things, whether ultimate recovery could be affected by production rate. Such surveillance should include the totalling, averaging or analysis of trends of well data and also comparison of pool performance with appropriate surveillance criteria and with predictions based upon reservoir studies.

8 METHODS OF SURVEILLANCE

In section 7 of this report the Board concluded there is a continuing need for surveillance of both individual well and pool production rate to identify situations where crude oil production rate may affect ultimate recovery. In this section it reviews the methods of surveillance which are currently used, the new methods of surveillance which were proposed at the hearing, and gives its views as to what would be appropriate now and for the future.

8.1 Screening Criteria

The rationale for using screening criteria is to separate or screen those cases where it is generally accepted that production rate will have no significant effect on ultimate recovery of crude oil from those cases where further study is warranted. These criteria can be applied to individual wells, groups of wells or entire pools.

Methods for screening the effects of individual well production rate on recovery include the comparison of current data on production rate, GOR, WOR and pressure performance with historical trends in the same well or other similar wells or with some predetermined criteria. The present practice of assigning different GOR and WOR schedules and the minimum producing requirements for wells in blocks are examples of predetermined surveillance criteria for individual wells. These methods could be extended to include the comparison of data on physical properties, economic factors and physical facilities with some appropriate criteria.

Methods for screening the effects of pool production rate on recovery are similar to those for individual wells except the data are usually the averages for the pool. These methods could also include comparison of data on development practices, operating practices and economic factors with a prescribed formula or some appropriate criteria. The present PRL formula* is an example of this type of pool surveillance.

*The formula is given on page 3-2.

8.11 Views of the Participants

Board Staff

The Board staff did not propose any new surveillance criteria. It expressed some concern with screening methods or procedures which use pool average data rather than the raw data.

Several Participants

Representatives of Aquitaine, CPA, Home, IPAC, PanCanadian and Shell indicated a general acceptance of the PRL formula used by the Board since 1965 as a screening device for determining when MER or rate sensitivity studies should be required even though they did not support its use for setting MRLs.

Imperial

Imperial suggested that, if surveillance on a pool basis were considered necessary, an arbitrary screening formula to direct attention to pools where annual production exceeded 10 per cent of the initial recoverable reserves would be appropriate. It considered this to be a conservative criterion and that there should be no concern that recovery losses would occur at pool rates up to the 10 per cent level.

Mobil

Mobil proposed the use of a Conservation Surveillance Index (CSI) for determining those pools which should be considered for an MER review. A common CSI would be selected by the Board to reflect a safe minimum life index (remaining recoverable reserves divided by current annual production rate) for all pools in the Province. Mobil recommended that when the life index for a particular pool was less than 6 years, an MER review would be warranted.

Texaco Exploration

Texaco Exploration suggested that for thin, low permeability, horizontal water flood reservoirs, the grouping kh/μV could be used as a screening device to determine those cases where recovery could be considered insensitive to production rate. Based on some data for the Pembina Cardium reservoir, it suggested that if kh/μV was less than 4000 to 5000 md-ft/cp recovery would not be sensitive to rate.

For reservoirs with vertical displacement of oil by water, Texaco

Exploration suggested that the velocity of the oil-water interface could be used for screening reservoirs where recovery would not be adversely affected by rate. By applying Darcy's law in the oil zone immediately above the oil-water interface, it proposed that if the superficial interface velocity (bbl/ft^2/day) were less than 0.4 k_o/μ_o, the displacement would be gravity dominated, a high displacement efficiency could be expected and presumably recovery could be assumed independent of production rate.

8.12 Views of the Board

The Board recognizes that no single criterion or simple formula can be entirely suitable for screening all types of wells and pools and all types of recovery mechanisms to determine levels of production above which recovery may be sensitive to rate. None the less the Board sees merit in having available several reasonable guides to determining where production rates may be approaching or have reached levels where detailed rate sensitivity studies should be made.

The Board's PRL formula, the present proposal of Imperial and the suggestion of Mobil are all rather similar, as indicated by Figure 8.1, and serve to define a broad band separating rates above which rate sensitivity studies might be required and below which recovery could safely be assumed independent of rate. Even though the indicated band is broad and its boundaries are arbitrary, the Board believes that, along with judgement and other criteria reflecting the nature of individual reservoirs and their producing mechanisms, the three formulae will be helpful as screening devices. The Board also accepts the rationale behind the new pool surveillance methods proposed by Texaco Exploration. The methods should be aids to judgement and it should be possible to confirm or modify the proposed criteria based on field experience.

Although no new screening criteria were presented for surveillance of individual well rates the Board believes some new criteria could be helpful. For example, in water coning and water-flooding it may be useful to compare fluid production rates with the maximum capacity of installed bottom-hole pump equipment. It may also be possible and beneficial

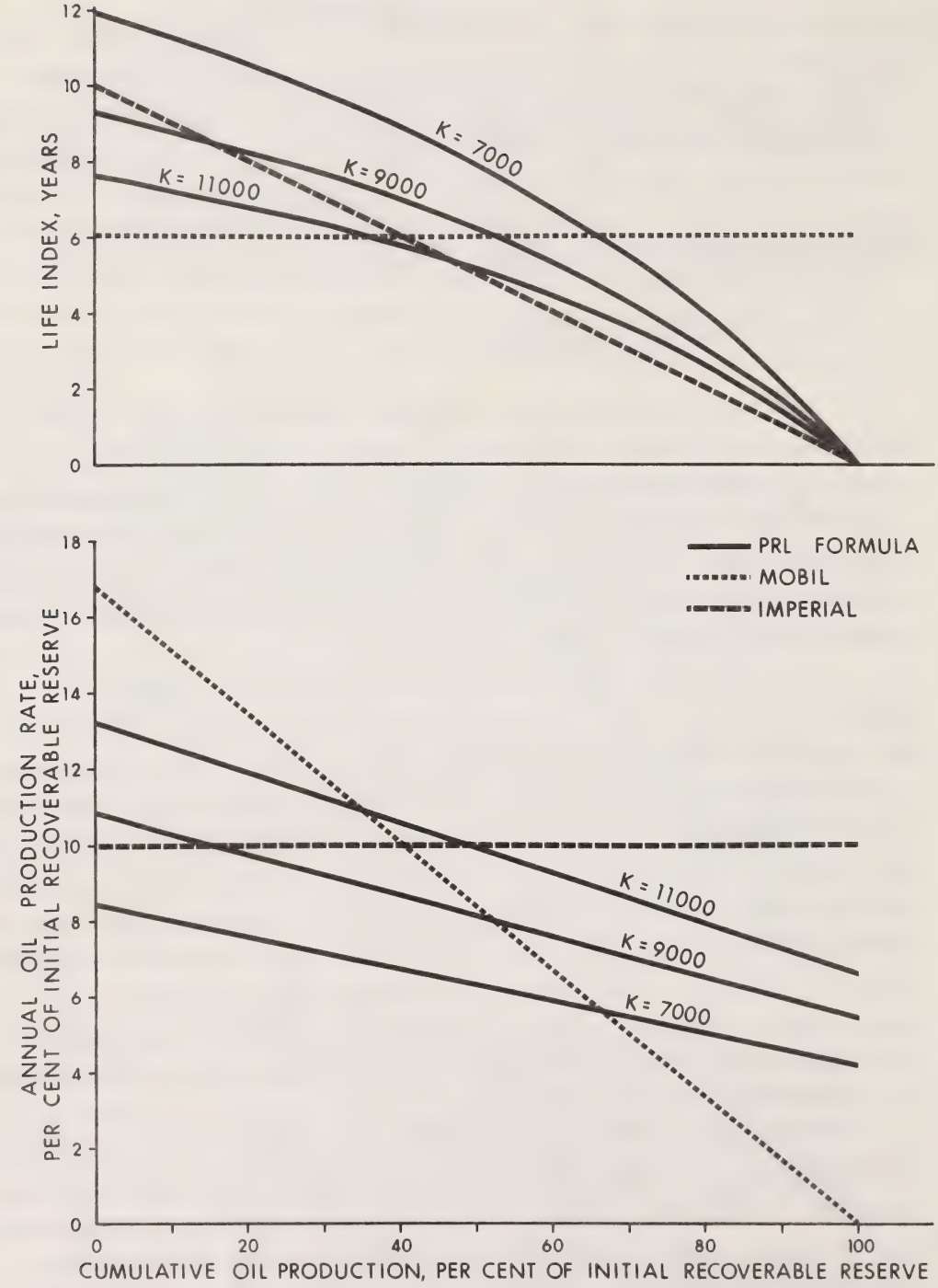

Figure 8.1 Comparison of Annual Oil Production Rates and Life Indices for Three Screening Formulae

to develop predetermined criteria for economic limits for different types of facilities.

The Board believes that screening methods should involve several tests or criteria. Thus, the urgency for thorough review of any particular case would increase as more of the surveillance tests indicated the need.

8.2 Methods for Surveillance of the Possible Effect on Recovery of Individual Well Production Rate

The surveillance of the possible effect on recovery of individual well production rate is that particular kind of surveillance which focuses on individual well characteristics, properties and performance. The scope of this kind of surveillance could include detailed analysis of the well production data, the well bore effects, and the adequacy of well completions and artificial lift equipment. It is of particular importance where pool recovery could be reduced because of uneconomic operating conditions for particular wells due to coning, stratified flood-out, etc. which could be attributed to high production rates.

8.21 Views of the Participants

Board Staff

The Board staff submitted that any method of surveillance of the effect on recovery of production rate should consider individual well performance since high GORs and WORs of individual wells may be masked in the averages for large production entities. It made no specific proposals.

Ashland

Ashland proposed that, for each reservoir to which fluids were being injected, maximum injection pressures be established consistent with good engineering practice.

Gulf

Gulf suggested that evaluation of well production tests at capacity provides a means to predict a safe drawdown rate from a reservoir damage standpoint. It stated that any conclusion derived with respect to well performance must be carefully examined, since the mechanical condition

of the completion and equipment can exert substantial influence.

Imperial

In submitting a proposed individual well surveillance method, Imperial postulated that high individual well rates could reduce the amount of economically recoverable oil only if all three of the following conditions were met:

(1) The well has become uneconomic to operate because of coning or channelling.

(2) There is insufficient economic incentive to support replacement of the well.

(3) There is no other well from which the oil could be produced.

The parameters required for the analysis are the remaining recoverable reserves of the average well of the pool, the average well producing capacity, and the drilling and completion costs of an average well.

Imperial stated that, using actual cost data, a family of curves for various well depths could be developed to define the combination of reserves and well capacity required to support the drilling of a replacement well and yield a satisfactory rate of return. Imperial submitted an example of such a chart based on a 10 per cent rate of return. This is reproduced in Figure 8.2. As an example, wells in a pool with an average depth of 5,900 feet and a remaining recoverable reserve of 150,000 bbl/well, should be reviewed before the average well capacity declines to 100 bbl/d.

8.22 Views of the Board

The Board believes Imperial's surveillance proposal concerning replacement of damaged wells has merit since it incorporates the significant economic factors. However, it is the Board's opinion that the method would be ineffective where there is a wide variation in well quality such that the average remaining reserve per well was not representative of the actual situation. The effects of inter-well communication and recovery of oil by adjacent wells usually requires a well by well economic analysis before the drilling of each infill or replacement well.

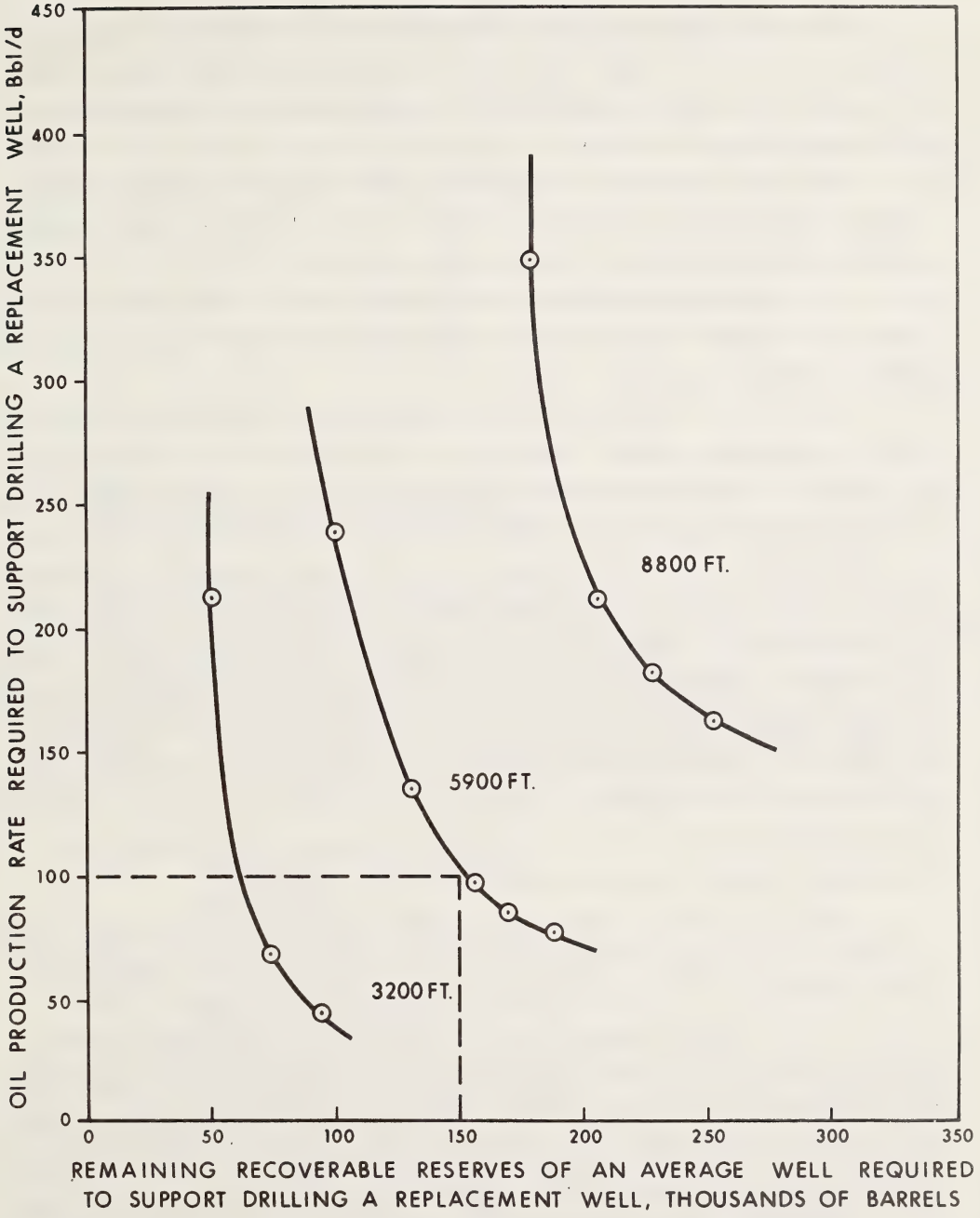

Figure 8.2 Example Chart (redrawn from Imperial's submission) Showing the Combination of Reserves and Productivity Required to Support Drilling of a Replacement Well

The Board believes that a comprehensive surveillance program to identify individual wells with potential problems involves three steps:

(a) The routine and periodic comparison of data from all wells with some screening criteria.

(b) The comparison of anomalous performance trends with similar trends in other wells with more production history or with generalized performance predictions for various well types.

(c) The making of special studies in a few special cases to assure that major changes in rate or other operating practices will not adversely affect ultimate recovery.

The Board's production accounting procedures are the first step in this surveillance program. These procedures require that individual wells be tested at least once per month and in the event of adverse performance the required testing frequency is increased. The Board keeps close watch on individual well performance data such as monthly production, GOR and WOR. In the event of adverse performance, it has tended to rely on GOR and WOR penalties to adjust producing rates to appropriate levels. These penalties were developed to satisfy both conservation and equity concerns. In pools where water is returned to the reservoir and gas is reinjected or otherwise conserved, the Board has based penalties on net production. In a few cases where operators have made application, the Board has waived penalties provided it was not considered detrimental to recovery or to correlative rights. These procedures will be continued.

The second step of the surveillance program involves trend analysis and this is often part of the Board's review of the annual progress reports submitted for enhanced recovery schemes. Less frequently it involves comparison with engineering predictions. In some pools operators have voluntarily submitted coning studies and while these have been primarily used for estimating sandwich losses for reserve evaluation, in a few cases they have been used for surveillance purposes. Again, these procedures will be continued and strengthened.

The Board has not made a general practice of requiring special individual well studies or of requiring multipoint flow tests to evaluate inflow performance relationships for crude oil wells similar to those

routinely required and submitted for gas wells. Although such tests are useful for evaluation of individual well performance, the Board recognizes that they can be very expensive and often are not possible to conduct because of well bore restrictions caused by artificial lift equipment. None the less the Board believes that this type of testing is a necessary part of any plan to optimize pool recovery by variations in production rate. The Board notes that significant advances in diagnosis of sucker rod pump problems have been made in recent years and it believes this type of analysis may be required to sustain high production rates. The Board will expect that appropriate individual well tests and studies will be conducted when the need for them is indicated.

8.3 Methods for Surveillance of the Possible Effect on Recovery of Pool Production Rate

The surveillance of the possible effect on crude oil recovery of pool production rate is that particular kind of surveillance which focuses on pool performance characteristics, drive mechanisms, gas-oil and oil-water interface movements, and both inter-pool and intra-pool pressure interference. It also includes comparison of actual performance and recovery with those predicted in reserve, MER or rate-sensitivity studies.

8.31 Views of the Participants

Board Staff

The Board staff did not propose any new or specific methods for surveillance of the possible effect on recovery of pool production rate.

Industry Participants

The majority of the industry participants contended that within the normal range of pool production rates, crude oil recovery from most pools would not exhibit any sensitivity to rate, and no new methods of surveillance were proposed. There was general agreement among industry participants that pool MER studies are the most reliable means for detecting or assessing any rate-recovery sensitivity.

8.32 Views of the Board

The Board's practice for the past many years has been to maintain a close watch on such important pool characteristics as reservoir pressure and significant pressure gradients, average GOR and significant GOR gradients, average WOR and significant WOR gradients, overall replacement of reservoir voidage, rate of advance or gas-oil and oil-water interfaces and other characteristics indentified in specific Board Approvals. In addition, the Board has compared pool production rates with the pool PRLs and where it appeared appropriate has requested MER or other reservoir studies from the operators. During the period 1950 to 1960, the operators voluntarily conducted classical MER studies (evaluation of combination drive indices) for the major D-2 and D-3 pools and submitted them to the Board. Since 1960, detailed reserve studies have always been made available in connection with applications for approval of enhanced recovery operations. The Board has requested comprehensive reservoir studies for several of the larger Beaverhill Lake Pools and rate-recovery projections have been submitted or are in preparation. While few of the studies have focused specifically on the matter of the sensitivity of recovery to production rate, most of them have dealt with the recovery expected at the anticipated pool production rate.

The Board believes it appropriate to continue its field and office surveillance of the important pool characteristics as mentioned above and, with the help of the screening devises discussed in Section 8.12 and where appropriate, to request from the operators detailed studies of the expected reservoir performance and resulting recovery for a range of crude oil production rates. These studies would supplement the normal reservoir studies which might accompany applications for enhanced recovery operations. They would be along the lines suggested by Gulf, Hudson's Bay, Imperial and other industry participants. Where the studies indicated, and the operators requested, that pool production rates in excess of those defined by the "screening band" be permitted, the Board may ask that the studies be subject to scrutiny at a public hearing.

9 THE NEED FOR REGULATION OF PRODUCTION RATE

In this section the Board reviews the general need for regulation of crude oil production rate and the particular need for regulation of individual well and pool production rate to achieve maximum recovery.

9.1 The Need for Regulation of Individual Well Production Rate

The present proration plan fulfills the need to regulate the provincial crude oil production to the market demand and the need to afford each owner the opportunity of obtaining a share of the market demand for crude oil. The proration plan does not necessarily fulfill any need for regulation of individual well production rate to achieve maximum recovery, since this is an objective of the MRL plan. Although the MRL plan provides for the setting of individual-well daily or monthly MRLs where there is a particular need such as a consequence of an MER study, the more general practice has been to apply the PRL formula and distribute the pool MRL to the various production entities on the basis of their productive acreages.

9.11 Views of the Participants

Board Staff

The Board staff contended there is a general need for regulation of individual well rates. This position was based on the following:

(a) Ultimate pool recovery was considered to be the sum of individual well recoveries in most horizontal and in some vertical drives, and any factors affecting well recovery in these cases would also affect the pool recovery.

(b) It was considered that uniform and equitable application of GOR and WOR penalties requires that they be based on individual well performance since abnormal GOR or WOR performance of individual wells

can be masked in the averages of larger production entities (e.g. blocks, projects).

(c) High individual well production rates were considered to cause differential depletion and irregular advances of fluid interfaces, particularly in heterogeneous reservoirs.

(d) It was considered that regulation of individual well rates would tend to assure that every capable well is operated to its economic limit.

Alminex

Alminex contended that individual-well rate limitations were generally unnecessary and impractical, and should only be applied in extreme cases. Alminex did not state what would constitute an extreme case, but did state that lease boundary control for equity purposes should not be a consideration in establishing MRLs.

Amerada

Amerada acknowledged there could be some pools with gas or water coning problems where individual well MRLs would be required.

Amoco

Amoco stated the technical analysis of the effect of well rates on recovery efficiency suggests that the effect is negligible except in some possible coning situations. It contended the effect of production rate could be favourable or adverse depending on circumstances and that operators need full flexibility in setting individual well rates to achieve maximum recovery.

Ashland

Ashland submitted there is no need for rate restrictions (individual well) in horizontal water-floods provided reservoir voidage is replaced. It did propose, however, that limits be established for the injection rates and/or pressures of individual water injection wells.

Chevron

Chevron submitted there may be certain situations where the rate of withdrawal from individual wells could be detrimental to ultimate recovery. However, it proposed that all restraints be removed during the later stages of depletion.

Gulf

Gulf contended that in situations where MRLs are required there is a need for individual well rate limitations because of individual well phenomenon dealing with the mechanics of producing the oil. It expressed the opinion that changes in the reservoir recovery mechanism could be controlled by adjusting or regulating individual well draw-down.

Home

Home took the position there is no general need for regulation of individual well rates for conservation or equity reasons, but that there is a need for freedom to vary individual well rates to fit the particular situation. It stated the MRL system should not be used to restrict production to some uniform well rate nor to protect correlative rights within a pool.

Husky

Husky acknowledged that situations can develop where regulation of individual well production rates is required, but expressed the opinion that production rates from heavy-gravity oil pools are limited more by wellbore and operational problems than by reservoir factors. It submitted that in heavy-gravity crude oil pools an individual well MRL of 50 bbl/day would be conservative, but would be high enough to encourage exploration and development and permit operation without shut downs.

Imperial

Imperial submitted there was no need for regulation of individual well rates, and that restrictions which limit complete flexibility of well operation will reduce ultimate pool recovery.

Mobil

Mobil stated that individual well rates should not be limited by a preliminary rate formula. It contended the need for regulation of individual well rates should be decided after an MER review.

Petrofina

Petrofina submitted there may be a need for the determination of individual well MERs for wells that produce multiple allowables.

Union

Union submitted there was a need to regulate individual well rates to prevent excessive pressure draw-down.

9.12 Views of the Board

While the Board agrees that considerable flexibility is required to vary individual well rates in enhanced recovery projects, it believes there continues to be a need to regulate individual well rates in some special cases. This is in agreement with the majority of participants who spoke to the matter. The Board's view is based primarily on its conclusions in section 6 that in certain circumstances production rate can affect ultimate recovery and the realization that in some cases regulation of individual well rates is the only effective administrative procedure. The Board sees the need for regulation of individual well rates, beyond that required as a result of proration, in the following special cases:

(a) Where there is a need for regulation of pool production rate which can only be achieved through the regulation of individual well rates. Some pools under concurrent production are examples.

(b) Where regulation of pool rate is not required but where the loss or damage of an individual well could lead to a loss of recovery. Examples are: pools with wide spacing and marginal economics, pools which produce highly corrosive salt water or otherwise have high water handling costs, and pools where there is evidence that wells cannot be successfully reworked to repair wellbore damage due to coning.

(c) Where GORs and WORs are sensitive to rate or are variable and where it is necessary to control gas or water production. Examples are where a solution gas drive supplants a more efficient drive as a result of high production rates or where voidage in a localized area may otherwise not be replaced.

(d) Where there is potential for coning or cusping and wells are being produced at rates which cannot be sustained after breakthrough with the installed or planned facilities.

(e) Where a special need is established by the surveillance methods discussed in section 8. Examples are: where the displacement front is not progressing in the desired manner due to the lack of voluntary regulation of individual well rates, where unusual pressure gradients

develop, where wells are prematurely suspended, and where the conditions of a Board Approval are not being satisfied.

9.2 The Need for Regulation of Pool Production Rate

As discussed in section 3, the regulation of oil, gas, and water production rates has been a continuous undertaking of the Board since its inception. Pool gas and water production rates are usually regulated indirectly as a consequence of GOR and WOR restrictions, but may be directly regulated in special cases such as the concurrent production of a gas cap and oil zone. While the need for regulation of pool oil production rate for purposes of proration is clear, the concern here is the need to regulate pool production rate in the interest of achieving maximum practical and economic recovery of crude oil.

9.21 Views of the Participants

Board Staff

The Board staff submitted there is a general need for regulation of production rate and contended that present regulation of pool production rate was often too coarse to be fully effective.

Alminex

Alminex submitted that the reasons for the need for MRLs may need to be more widely understood by industry and the Board's staff. Alminex contended that the majority of pools are not adversely affected by high rates and that MRLs should be applied on a selective basis. It submitted two major areas for application of MRLs are new pools and where rate sensitivity can be proven to be significant.

Amerada

Amerada submitted there was no general need for MRLs but recognized some pools may have gas coning or water coning tendencies which require MERs calculated on a pool by pool basis. Amerada recommended that no consideration be given to PRLs.

Amoco

Amoco contended there is no general need for MRLs and submitted that rate control in general is not an effective conservation device.

Aquitaine

Aquitaine questioned the need for regulation of pool production rate to prevent waste and advocated the general application of the Board's GPP guidelines provided not much weight was given to the requirement that pools eligible for GPP be in the later stages of depletion.

Ashland

Ashland did not comment on the general need for regulation of pool production rate, but submitted that there is no need for regulation of production rate of horizontal water-floods in sandstone reservoirs provided all reservoir voidage is replaced.

Chevron

Chevron contended that the ultimate recovery from all pools is not rate sensitive within the normal range of production rates experienced in Alberta pools. It recommended that MRLs be applied only where surveillance indicates there is a need.

D&S

D&S stated there is no need to restrict the production rates during the exploration and development period when a pool is on primary depletion. It contended that removal of MRLs during development would provide the economic incentive for rapid development of new pools, especially those with marginal economics, which in turn could accelerate the installation of enhanced recovery schemes.

Dome

Dome submitted that in pressure maintenance projects the main criterion for reservoir control should be a balance of injection and withdrawals, but beyond this restriction rate limitations for many reservoirs may not be necessary. It also submitted that during the early life of pools (i.e. until sufficient data is available for rate-sensitivity studies) the present PRL formula could be applied.

Great Plains

Great Plains proposed that no MRLs be set for horizontal water-flood pools if good production practices including replacement of voidage, strict control of producing GORs, and appropriate operational strategies are maintained. It also proposed that no MRLs be set for fully pressure maintained reservoirs produced by vertical displacement mechanisms.

Great Plains submitted that based on its studies for these types of pools there was no adverse effect of production rate on ultimate recovery and therefore no need for regulation of pool production rate.

Gulf

Gulf contended there is no general need for regulation of pool production rates and that MRLs should be imposed only in the few reservoirs where significant oil conservation benefits can be reasonably expected.

Home

Home submitted that physical conservation and prevention of economic waste can be achieved without recourse to an MRL system and regulation of pool production rate.

Hudson's Bay

Hudson's Bay stated that rate restrictions are generally not necessary since it contended ultimate recovery in most pools is not significantly affected by production rate within economical and practical ranges. It also stated that the setting of MRLs for pools producing heavy crude oil is undesirable because of the marginal economics in the development of these pools.

Imperial

Imperial contended that MRLs are required only in exceptional situations where a change in the displacement mechanism could occur if rates were increased.

It submitted that there are provisions within the current regulations and approvals to safeguard against the exceptional situations where rate restrictions are required. Imperial stated:

> "from the stand point of ultimate pool recovery there is no need for rate restriction on either a pool-wide basis or individual well basis so long as there is sufficient economic incentive remaining to support the replacement of wells whose abandonment without replacement could result in a reduction in ultimate recovery".

Imperial recommended that individual pool studies form the basis for establishing MRLs where required and that any general type of formula should be used solely as a surveillance tool. Imperial recognized there may be a need for MRLs in vertical miscible displacement processes to ensure the integrity of the solvent slug.

Mobil

Mobil submitted that under certain conditions the ultimate recovery from a pool can be affected by production rate, but that the sensitivity of recovery to rate can be established only by considering individual pool characteristics (e.g. individual reservoir studies for MER purposes). Mobil stated that no pool should be limited in production as a consequence of a PRL, rather the need should first be established, preferably by MER studies.

Shell

Shell submitted that MRLs are neither necessary nor appropriate for the prevention of reservoir waste in the majority of pools in the Province of Alberta. It considered the need or otherwise for MRLs to be primarily a function of pool type and recovery mechanism.

Texaco Canada

Texaco Canada stated that MRLs should be imposed only in cases where studies substantiated by reservoir performance indicate reservoir waste.

Texaco Exploration

Texaco Exploration acknowledged the need for limiting production rates where waste is occurring or ultimate recovery is jeopardized, but contended that the general need for MRLs cannot be readily established for the majority of the pools in the province.

Union

Union submitted there is a need for MRLs since it is possible to produce an individual reservoir at rates sufficiently high that the ultimate recovery from the pool could be adversely affected.

9.22 Views of the Board

The Board agrees with the widely expressed view of the industry participants that there is no universal need for regulation of pool production rates. In particular there would appear to be no general need for such regulation in fully pressure maintained horizontal or vertical waterfloods. However, the Board continues to believe, in agreement with some

participants, that there is a need to regulate pool production rate beyond proration in some cases. This view is based primarily on the Board's conclusions in section 6 that in certain circumstances pool production rate can affect ultimate recovery. The Board sees a need to regulate pool production rate in the following cases:

(a) Where pools are subject to miscible displacement processes, including vertical drive solvent schemes in heterogeneous reservoirs.

(b) Where the need for regulation of individual well production rates effectively controls the pool production rate or where the loss of a well will lead to a loss in pool recovery. This is most likely to occur in small pools with few wells.

(c) Where pools are under concurrent production of the gas cap and oil zones.

(d) In some cases where pools are inter-connected by a common aquifer.

(e) In pools where the effects of capillary pressure, wettability and relative permeability are likely to be significant and their effect on recovery either have not been appraised or are such as to require control of production rate.

(f) In pools where the fluid properties and recovery process are such that significant changes in fluid composition may occur in the reservoir.

(g) In pools that are produced at rates which cannot be sustained after breakthrough of displacing fluids with the installed or planned facilities. Examples are pools without water disposal facilities, several pools serviced by a single multi-phase gathering system, and pools where the well completion effectively prevents installation of high capacity artificial lift equipment.

(h) In pools where the need is established by the surveillance methods discussed in section 8. Examples are natural or induced displacement schemes where the desired movement of displacement fronts, vertically or horizontally is not occurring and no voluntary rate control is being applied, cases where high rates cause a change in drive mechanism to the detriment of recovery, and pools where the operations are in contravention of Board Orders or Approvals.

10 METHODS OF REGULATION OF PRODUCTION RATE

In sections 6 and 9 of this report the Board concluded that under certain conditions production rate can affect ultimate recovery and that under those conditions there is a need to regulate production rate. In this section the Board reviews the current method of regulation and the methods of regulation proposed at the hearing.

10.1 Methods of Regulation of Individual Well Production Rate

Details of the Board's present method of regulating individual well production rate is given in section 3. The highlights are as follows. Where pool MRLs are set, and whether or not the pool is subject to pro-rating, the pool MRL is distributed among the producing entities (PSUs, blocks and projects) in accordance with their productive acreage. Under this method of distribution, individual well rates are specified only for PSUs outside of blocks or PSUs with control-well status. The entity production rates so determined are subject to GOR and WOR penalties on the production data of the second preceding month and in the case of blocks and projects computed as if the production were from one well. They are also subject to off-target penalties.

The production accounting system requires that an "MRL overproduction" or "MRL underproduction" status be carried for each PSU, block, or project. Where the monthly production is in excess of 120 per cent of the MRL, a direct penalty is imposed by increasing the cumulative MRL overproduction or decreasing the cumulative MRL underproduction of the production entity by an amount equal to the monthly production in excess of 120 per cent of the MRL. The system also provides for a direct penalty if the cumulative production is in excess of the cumulative MRL for any six-month period ending at the end of April or October.

10.11 Views of the Participants

Board Staff

The Board staff proposed that an MRL determined for a pool or a portion thereof (MRU), either as a result of an MER-type study or on an

interim basis through a modified PRL formula, would be distributed among the individual wells involved on the basis of their DSU acreage. Its proposal for a pool or portion of a pool is presented in Section 10.21.

To provide a controlled measure of flexibility to individual wells within each MRU, the Board staff proposed that any well be permitted to produce at rates up to M times the acreage allocation for its DSU. The ability of an individual well to safely produce more than its acreage allocation was taken to be proportional to the product of the oil mobility and the initial oil-in-place per acre with a minimum value of one. The initial M-factor for a MRU would be determined from the relationship

$$M_i = 1 + \log_{10} \{(k/\mu)\ (N/a)\}$$

where:

k/μ = the average value of oil mobility in the MRU, md/cp.

N/a = the average value of the initial oil in place in the MRU, thousands of stock tank bbl/acre.

It was further proposed that the M-factor be decreased annually having regard for the cumulative production from the MRU. Thus, the M-factor for each MRU would be related to M_i by the relationship

$$M = M_i \{1 - P/(2U)\}$$

where:

P = cumulative production for the MRU to the end of the preceeding calendar year, stock tank bbl,

U = initial recoverable reserves for the MRU, stock tank bbl.

The Board staff proposed an MRL accounting method similar to that presently used. Production from an individual DSU would be restricted to the limit determined by multiplying the DSU base MRL by the M-factor and applying GOR, WOR and off-target penalty factors. Monthly production from a DSU in excess of 120 per cent of its MRL would be subject to a direct penalty by increasing the cumulative MRL overproduction or decreasing the cumulative MRL underproduction by an amount equal to the

monthly production in excess of 120 per cent of the MRL. Overproduction penalties would also be applied if the monthly production from a block, project or MRU exceeded 120 per cent of their respective MRLs or if the cumulative production were in excess of the cumulative MRL for any six-month period ending at the end of April or October.

The Board staff stated the belief that the concept of MRUs, M-factors and the production accounting procedure were sufficiently flexible that they could be used to distribute and administer MRLs resulting from MER or equivalent studies.

Gulf

Gulf proposed that in those cases where significant oil conservation benefits could be expected that rate limits should be administered on a per-well bases. The following formulae were proposed for determination of maximum individual well rates:

$$Q = \frac{3.075\ kh\ (P_e - P_w)\ S}{\mu \log\ (r_e/r_w)}$$

where: Q = well rate limit, bbl/day,

k = pore volume weighted average horizontal permeability, darcies,

h = pore volume weighted average reservoir thickness, ft, determined by the relationship

$$= \frac{\text{Initial Pool Hydrocarbon Volume}}{7758\ A\ \emptyset\ (1 - S_w)\ S}$$

A = pool validated acres,

$\emptyset$ = porosity, fraction

S_w = connate water saturation, fraction

$P_e - P_w$ = pressure drawdown between external drainage radius, psi, established at the "safe" level by the relationship,

$$= 0.05\ P_F \sqrt{L}$$

P_F = subsisting static reservoir pressure, psi,

L = number of 40 acre legal subdivisions in the PSU for the well,

S = oil shrinkage factor at initial pressure,

μ = oil viscosity at initial reservoir pressure, cp,

r_e = radius of external boundary of well drainage area, ft, arbitrarily determined by the relationship

$= \sqrt{(40)\ (43560)/\pi}\ \sqrt{L}$

r_w = radius of the wellbore, arbitrarily set at 0.5 ft.

Gulf endorsed the position of the Board staff in submitting that pools should be subdivided into producing areas having common reservoir quality and displacement mechanism for purposes of administering MRLs.

Gulf further submitted that for any pool where use of its proposed formula resulted in individual well rates which endangered correlative rights, conservation or reasonable economic development incentives, provision already existed within the Oil and Gas Conservation Act for either the pool owners or the Board to request and prepare information for setting a specific set of administrative rules for the pool. Gulf believed that rate based on a well-documented MER study was preferable to an MRL determined by general formula.

Shell

Shell stated that acreage distribution of an MRL within an MRU could negate the benefits of imposing an MRL. It stated that an MRL should be distributed to individual production entities on the basis of the parameters which caused the need for the MRL.

Texaco Exploration

Texaco Exploration proposed that any pool MRL be distributed among individual wells in proportion to the ultimate reserves of the individual wells. It submitted this could be achieved by a procedure which recognizes well bore pay thickness and area.

Union

Union proposed that pool MRLs, determined as described in section 10.21, be distributed to individual wells on the basis of their DSU acreage with the safeguard that individual well rates would be restricted to prevent excessive pressure draw-down. It proposed that allowable transfer be related to a common acceptable pressure draw-down. Union proposed the following procedure.

(a) Permit transfer of allowables up to five times the DSU allowable based on the relationship

$$Q = (T_c)\ (DSUA)$$

where: Q = maximum individual well production rate,

$T_c = (C_1)\ \{k/(\emptyset\mu c)\}$

= correlation transfer coefficient (well allowable/DSU allowable), which recognizes the reservoir's response qualities, $1.0 \leq T_c \leq 5.0$,

C_1 = a constant relating T_c to reservoir parameters,

k = average reservoir permeability,

$\emptyset$ = average reservoir porosity

μ = oil viscosity at reservoir conditions,

c = oil compressibility at reservoir conditions,

DSUA = drilling spacing unit allowable.

(b) Permit greater transfer of allowable than calculated in (a) if pressure draw-down is measured or if it can be calculated from a measured inflow performance relationship (IPR).

$$Q = (T_f)\ (DSUA)$$

where: $T_f = (C_2)\ (PI/DSUA)$

= field measured transfer coefficient, (well allowable/DSU allowable), $T_f \geq T_c$,

C_2 = an acceptable pressure draw-down related to the properties of reservoir,

PI = productivity index of the producing well at the proposed production rate.

Others

Alminex supported the present method of acreage distribution of MRLs to individual production entities.

Ashland proposed that the present acreage distribution of MRLs be retained for horizontal sandstone pools on primary production.

Several other participants gave qualified support for the continued use of acreage distribution of pool MRLs to individual production entities.

10.12 Views of the Board

The Board distinguishes between the situations where regulation of individual well production rate is required: (a) as a consequence of the need for regulation of the rate of production from the pool as a whole and, (b) for the purpose of ensuring that recovery is not affected through excessive production rates of individual wells.

In situations of the first type the Board agrees with the Board staff and many of the industry participants that the pool MRL should be dsitributed to individual wells on a basis related to acreage, or acreage weighted by reservoir properties. From the evidence presented at the hearing, the possibilities for distribution appear to be by:

(a) PSU acreage,

(b) PSU acreage modified by reservoir properties,

(c) DSU acreage modified by reservoir properties, or

(d) DSU acreage incorporating a flexibility multiplier such as proposed by the Board staff and Union.

The Board notes that the current rules for establishing PSUs give some weight to reservoir properties and also provide some flexibility of operation having regard for lease ownership. Having regard for this the Board believes that, as a general rule, the distribution to individual wells of the MRL of a pool or a portion thereof should be on the basis of PSU acreage - i.e. by method (a). This would maintain compatibility with the allocation of a pool's share of the provincial allowable to the wells in the pool under the Proration Plan and is administratively convenient. Where all wells have adequate capability the total of the individual well allocations would equal the MRL for the pool or portion. Where some wells are incapable of producing their acreage share the distribution would be based on a suitably adjusted MRL so that the expected production from the pool or portion would equal the actual MRL. The adjustment to the MRL would provide for incapability but not for any applicable GOR or WOR restriction.

The Board recognizes that there will be situations where some modification to MRL allocation on the basis of PSU acreage will be appropriate in the interests of conservation and will consider any such cases on their individual merits.

In situations of the second type, where restriction of the pool withdrawal rate is not required but where the operation of individual wells may result in a loss of recovery from the pool, the Board believes that the maximum well rates should be determined having regard for the individual-well properties and production characteristics and any facility constraints. Preferably a coning or other study would provide a basis for setting maximum rates. Failing this, or on an interim basis, use of the radial flow formula with a judgement draw-down, as suggested by Gulf and Union would seem appropriate.

10.2 Methods of Regulation of Pool Production Rate

Details of the methods now used by the Board to regulate pool production rate are given in section 3. The highlights are as follows: For pools subject to prorating the maximum allocation to the pool under the proration plan is the pool MRL as established by the Board as a result of an MER-type study, the PRL formula or by judgement. Where the pool allocation through prorating is less than any reasonable estimate of its MER or PRL the Board does not establish an MRL. For pools not subject to prorating and producing under GPP, MRLs may be set as above but are not set where the physical productivity in the pool limits production to low rates. For pools not subject to prorating and not producing under GPP, MRLs may be established by the Board as a result of an MER-type study but normally are set through the PRL formula or by judgement.

10.21 Views of the Participants

Board Staff

The Board staff contended that a pool is the largest meaningful regulatory entity for MRL administration and proposed the designation of MRUs consisting of whole pools or the portions of pools having similar rock and fluid properties and the same drive mechanism. It envisioned MRUs as small as single DSUs, blocks, and projects. It proposed that an MRL be determined for each MRU preferably by an MER-type study or on an interim basis by a modified PRL formula.

Where an MER or equivalent study was not available, the initial PRL for a MRU would be determined from the relationship

$$PRL_i = 0.06\ (N/a)^{0.175}(k/\mu)^{\{0.35 + 0.175 \log (N/a)\}}$$

where: PRL_i = initial PRL, bbl/day acre,

N/a = the average value of the initial oil in place in the MRU, thousands of stock tank bbl/acre

k/μ = the average value of oil mobility in the MRU, md/cp.

It was proposed that the initial PRL be adjusted downward annually having regard for the reservoir heterogeneity and the cumulative depletion. Thus, the PRL for each MRU would be related to PRL_i by the relationship

$$PRL = PRL_i \left\{1 - \frac{(1 + V)P}{2U}\right\}$$

where: V = the coefficient of variation of the permeability distribution within the MRU, dimensionless,

P = cumulative production for the MRU to the end of the preceding calendar year, stock tank bbl,

U = initial recoverable reserves for the MRU, stock tank bbl.

The Board staff acknowledged there were some serious deficiencies in its proposed PRL formula and stated that the current PRL formula gave more consistent treatment to all pools. It was of the opinion that the proposed formula could be improved, particularly by use of the geometric-mean permeability.

Home

Home contended that conservation objectives could be achieved without recourse to a rigid MRL procedure. It submitted that once a problem situation is identified it could be resolved by using procedures such as: private communication with pool operators; issuance of PSU, block, or project approvals containing any necessary restrictions on production and injection rates; issuance of pool-wide orders restricting excessive production of gas and water; issuance of punitive orders in those situations which require such actions, etc.

Hudson's Bay

Hudson's Bay proposed:

(a) continuation of the use and administration of the current PRL formula as a first stage in the control of production rates, and

(b) that operators be required to submit a depletion plan for a pool in order to reasonably optimize economic recovery and that after considering the submission the pool production rate be allowed to supercede that determined by the first stage PRL formula.

Husky

Husky proposed that the Board establish an MRL of 50 bbl of oil per day per well for all wells producing crude oil with an API gravity of 20^{o} or less.

Union

Union submitted a package proposal for future MRL administration. It proposed that PRLs be assigned to appropriate pools by the Board after the operator has been given an opportunity to make a PRL submission. The PRL would be determined in accordance with the guideline:

$$PRL = K (U - CP)$$

where:

K = a constant describing initial sensitivity of recovery to producing rate,

C = a dimensionless constant, describing the change in recovery sensitivity to producing rate with cumulative production,

= D/(1.2 K)

D = decline rate - per cent per year, $0 \leq D \leq 1.2K$

Union proposed that guidelines be established for assigning values of K and D for the following producing mechanisms: bottom water drive, flank water drive, gas cap drive, horizontal water flood, solution gas drive - light- and medium-gravity oil pools with the possibility to convert to another mechanism, solution gas drive - light- and medium-gravity oil pools with no possibility to convert to another mechanism, solution gas drive - heavy-oil pools, and other mechanisms.

In addition to the revised PRL formula, Union suggested that an MRL be assigned to an individual pool when a more sophisticated MER study was submitted and that production higher than the PRL be permitted to obtain information to more accurately define the true reservoir MER.

Others

There was general agreement among all industry participants that where MRLs are required they should be based on pool MER or equivalent stduies. Most industry participants were opposed to regulation by the application of a single formula. Many regarded the Board's staff submission as having given too much weight to simplicity of administration and held that administrative ease should be a subordinate consideration in any MRL system. Hudson's Bay and others pointed out that engineering manpower considerations would prevent performing detailed studies on all pools and suggested that the results of some thorough studies might be generalized to apply to other similar pools.

10.22 Views of the Board

In those reservoirs where regulation of pool production rate is found to be desirable or necessary the Board agrees with the general view of the participants that the preferred basis for MRL regulation is a comprehensive MER-type study incorporating a detailed consideration of the effect of rate on recovery under the practical, technical and economic limitations anticipated. The Board expects in some cases that MER studies will show that only portions of pools need regulation or that different portions require different levels of regulation having regard for the physical properties and production characteristics of the pool. In such cases the Board believes there is merit in the MRU concept and will designate MRUs where it believes it to be necessary for effective regulation of pool production rate. This, in fact, is the position which the Board has historically taken. The Board will request such studies where it appears appropriate on the basis of the surveillance methods discussed in section 8.

Where such studies are not available, for whatever reason, but where there are in the Board's opinion reasons to believe that pool recovery may

be sensitive to production rate, within the range resulting from any prorating, the Board will set an MRL for a pool or portion thereof guided by the criteria of Figure 8.1, the modifications to the PRL formulae proposed by Union and the Board staff, and by its own best judgement. Any MRL so set would be subject to reconsideration on the filing by the operators of a suitable MER-type study. This again is the position which historically has been held by the Board subject only to recognizing at this time that in some cases it is preferable to use PRL formulae which, even though arbitrary, have some regard for the important roles of reservoir permeability, crude oil viscosity and reservoir heterogeneity.

11 IMPLEMENTATION

The Board's findings in sections 6, 7 and 9 were that under certain conditions production rate can affect ultimate recovery and that there continues to be a need for surveillance and regulation of crude oil production rate. This is in general agreement with the Board's previous findings reported in Report OGCB 65-3. It is apparent now, however, that surveillance should be more intensive and that the application of MRLs should be more selective. The methods of surveillance and regulation discussed in sections 8 and 10 respectively are intended to broaden and intensify the Board's present surveillance procedures and to provide appropriate MRLs for the special cases requiring them. This section outlines the changes required to achieve these objectives.

11.1 Surveillance

The Board expects that the broadened and intensified surveillance methods of section 8 will:

(a) identify the pools or particular parts of pools where MER or rate-recovery sensitivity studies are required to ensure that present or possible future production rates will not adversely affect ultimate recovery,

(b) identify any cases where the requirements of Board Orders and Approvals are not being met, and

(c) identify cases of unusual or adverse production performance which, if allowed to continue, would reduce ultimate recovery.

To identify where MER or rate-recovery sensitivity studies are required, the PRL formula and the other reserves related criteria proposed by Mobil and Imperial will be applied to pools and to those parts of pools for which reserve estimates are available. The Board does not expect this type of surveillance to be very effective for many of the older pools, particularly during periods of proration. Moreover this surveillance does not indicate if studies of coning or other individual-well phenomena are required. The Board will rely on some of the new screening criteria discussed in section 8 to identify the latter cases. Rate-recovery sensitivity

studies would generally appear to be needed most in pools with any of the following conditions: highly heterogeneous reservoir rock, high oil viscosity, unfavourable mobility ratio, wide spacing, small production casing, and little flexibility of production handling facilities.

The surveillance to ensure that the requirements of Board Orders and Approvals are achieved will continue to be largely based on the annual progress reports required for enhanced recovery projects.

The Board will rely on the strengthened surveillance procedures discussed in section 8 to identify cases of unusual or adverse production performance. This particular kind of surveillance will be based on individual-well data rather than the averages for larger production entities. In addition to this type of regular surveillance by the Board staff, the Board expects that operators will continue and strengthen programs involving performance monitoring and the modification of operating practices to meet basic conservation objectives such as preservation of reservoir energy. It expects that surveillance will also be done to achieve other less easily defined objectives such as avoidance of coning and viscous fingering, optimum utilization of gravity where beneficial, viscous cross-flooding of tighter strata to improve recovery, optimum use of the installed facilities, etc.

11.2 Regulation of Production Rate

The Board will be more selective in its application of MRLs. Table 11-1 gives a general indication of the factors the Board will assess in determining the need for and level of pool or individual-well MRLs. The Board will remove MRLs on January 1, 1976, or as soon thereafter as preliminary investigations can be completed, from those pools where it appears that high production rates are not likely to adversely affect ultimate recovery. It will remove MRLs from pools and individual wells where studies or detailed investigation show the effect of rate to be small or of uncertain magnitude, but it will strengthen surveillance of these cases. In the event of adverse performance the Board would reapply the PRL or other appropriate measures until the performance could be

TABLE 11-1

FACTORS TO BE ASSESSED IN DETERMINING THE NEED FOR AND LEVEL OF MRLs

Factor	Cases judged least sensitive to production rate	Cases judged most sensitive to production rate
Rock Properties	homogeneous, randomly heterogeneous, high permeability	highly heterogeneous, stratified, low permeability
Fluid Properties	low oil viscosity	high oil viscosity
Rock-Fluid Properties	wettability and capillary pressure complementing the drive mechanism, favourable mobility	rock-fluid properties not complementing the drive mechanism, unfavourable mobility
Recovery Mechanism	pressure maintained water-flood	combination drive, miscible flood
Development Practice	full operational flexibility (e.g. close spacing, large casing, in-pool water disposal facilities)	limited operational flexibility (e.g. wide spacing, small casing, no in-pool water disposal facilities, satellite batteries and long multi-phase pipe lines)
Performance Characteristics	producing GOR close to solution GOR, high and uniform reservoir pressure, uniform interface or flood-front advance	producing GOR in excess of solution GOR, low or erratic reservoir pressure, irregular interface or flood-front advance

shown not to have an adverse effect on recovery or until it had otherwise improved. It would also reapply rate restrictions or other appropriate measures if new knowledge or understanding indicate the need. The Board expects that revised pool and individual-well MRLs will be established for implementation on May 1, 1976, or as soon thereafter as practical, in those cases where MRLs are judged or proven to be necessary. The present MRLs will apply in the interim. The exact timing and administrative details of these changes will be announced by informational letters.

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APPENDIX A

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD

Informational Letter
No. IL 71-5

TO: All Operators

Maximum Rate Limitation

Most well owners are aware that, since crude oil demand has recently climbed to new high levels, there are certain pools or portions of pools (i.e., PSU's, blocks and projects) in which production might exceed the acreage equivalent of the pool Maximum Rate Limitation (MRL) or Preliminary Rate Limitation (PRL). In accordance with its Maximum Rate Limitation policy for crude oil pools*, the Board is now considering ways of introducing an acreage equivalent MRL or PRL for pools or portions of pools which would limit production to an appropriate maximum rate above which damage may occur. Provision would be made for adjustment of the limit following a submission by an operator for an MRL for a pool or part of a pool.

The purpose of this letter is to alert those operators now planning changes in production or marketing facilities of the possibility of crude oil production rates being restricted in accordance with the Maximum Rate Limitation policy. The Board expects to implement whatever measure that may be necessary by July, 1971, and it may seek the views of industry with respect to a specific plan.

ISSUED at the City of Calgary, Alberta, this ninth day of March, A.D. 1971.

OIL AND GAS CONSERVATION BOARD

A. F. Manyluk
Deputy Chairman

*Report and Decision on Review of Plan for Maximum Oil Production Rate Limitation in Alberta. March, 1965. OGCB 65-3

APPENDIX B

THE PROVINCE OF ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Informational Letter
No. IL 71-22

TO: All Operators

Maximum Rate Limitation in Light and Medium Crude Oil Pools

In March 1971, the Board issued Informational Letter No. IL 71-5 alerting operators of oil wells and pipe lines that the Board was considering ways of introducing maximum rate limitations for light and medium crude oil pools by July 1971. Having reviewed the matter the Board finds that, at the moment, there are only a very few instances where MRL's may be necessary. The Board therefore proposes to defer action on this matter, and will not implement a broad plan of maximum rate limitation at this time. However, it intends to continue its studies and may, on an individual basis, assign MRL's in those pools where it appears warranted.

The existing system of MRL's in heavy gravity crude oil pools will continue.

ISSUED at the City of Calgary, in the Province of Alberta, this 11th day of August, A.D. 1971.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

APPENDIX C

THE PROVINCE OF ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Informational Letter
No. IL-OG 73-24

To: Crude Oil Producers, Oil Purchasers
and Pipe Line Companies

Proration Plan and
Maximum Rate Limitations

1. With the high market demand of recent months resulting in capacity production of crude oil from many pools, the Board recognizes that

(a) a considerable number of additional pools properly could be granted "Good Production Practice" (GPP) status and, within the broad provision of the Proration Plan, permitted to produce without specific limit on crude oil rate but subject to other appropriate conservation conditions; and

(b) some pools are producing at rates which suggest that Maximum Rate Limitations (MRL) should be imposed on the allowables which would otherwise result from the application of the Proration Plan. This possibility was foreseen when the Plan was first developed and is discussed in Reports OGCB 64-10(1) and OGCB 65-3(2).

The Board is prepared to grant GPP status to those pools or separable portions thereof listed in Appendix I. GPP status will be granted effective November 1, 1973, subject to any objections received before October 1, 1973, and to completion of a further review by the Board staff. IL-OG 73-23 listed those pools which will be granted GPP status effective September 1, 1973, as a result of an application by Dome Petroleum Limited. The MD Order provides a complete listing of pools currently subject to GPP. The Board will consider in the normal way applications for the granting of GPP status to other pools.

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(1) Report and Decision on Review of Plan for Proration of Oil to Market Demand in Alberta, July 1964, pp. 151, 183.

(2) Report and Decision on Review of Plan for Maximum Oil Production Rate Limitation in Alberta, March 1965, pp. 80-85.

Appendix II is a listing of those pools whose allowables will vary with monthly market demand requirements.

The Board is reviewing the possible need for the application of MRL's to the pools listed in Appendix III. In this review the Board is making reference to available Maximum Efficient Rate (MER) or related pool reservoir studies and to its PRL formula in the form

$$PRL = 7000 \times 10^{-6} (U - P/2)$$

where: PRL is the Preliminary Rate Limitation for a pool or separable portion thereof, barrels per month(2).

The tentative MRL's proposed by the Board are shown in Appendix III. The Board will consider any submissions received by October 1, 1973, with respect to any of the MRL's shown in Appendix III. Then, effective November 1, 1973, the Board will apply MRL's within the Proration Plan to those pools or separable portions thereof listed in Appendix III where it considers MRL's to be desirable. All MRL's will be subject to review and possible redetermination pending the Board's decision on the following matters.

2. The Board also recognizes that the relationship between the market demand and the productivity for crude oil expected in the future is such that a plan for proration to market demand may not be required in the future and that crude oil production rates may only need regulation through suitable MRL's or GPP and application of GOR, WOR and other appropriate factors. The Board proposes to call a Public Hearing toward the end of March 1974 to review and consider the need or otherwise for continuing its system of proration and also review and consider methods of establishing MRL's whether for use within the Proration Plan or following its possible termination. A detailed Notice of Hearing will be published during the month of February 1974.

ISSUED at Calgary, Alberta, on July 30, 1973.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

APPENDIX D

ENERGY RESOURCES CONSERVATION BOARD

Proceeding No. 7511

NOTICE OF HEARING

Proration Plan and Maximum Rate Limitations

WHEREAS for the prevention of waste and for conservation purposes, it has been the practice of the Board to limit maximum production rates of crude oil from individual wells and pools by application of maximum rate limitations (MRL's) and the Board plans to continue such limitations and has decided to review the method by which it is done, and

WHEREAS it appears desirable to review and consider the need or otherwise for continuing the system of proration and also review and consider methods of establishing MRL's whether for use within the Proration Plan or following its possible termination, and the Board shall hold a hearing for such purposes in accordance with its Informational Letter No. IL-OG 73-24.

THEREFORE, TAKE NOTICE that the Energy Resources Conservation Board will hold a public hearing at the Court House, Calgary, Alberta, on Wednesday, March 27, 1974 at the hour of 9:00 a.m., for the purpose of receiving representations concerning

(a) methods for determining maximum rate limitations of production of crude oil from individual wells and pools or parts of pools,

(b) the need or otherwise for continuing the existing system of allocation of that portion of the provincial allowable for crude oil not supplied by synthetic crude oil and specifically the allocation to pools and wells of those portions of the provincial allowable to be supplied by

  (i) light and medium crude oil from pools now subject to prorationing, and

  (ii) black or heavy crude oil now subject to MRL.

The Board staff will file a submission concerning a proposed method for determination of MRL's and procedure for administration to be available on January 31, 1974.

Any person intending to make a submission with respect to this proceeding shall file, on or before February 28, 1974, ten copies of the submission with the Board at 603 - 6th Avenue S.W. Calgary, Alberta, and submissions so filed will be available for public inspection after March 4, 1974 at the offices of the Board at that address.

Any person wishing to file a submission in response to a submission filed in accordance with the preceding paragraphs shall file ten copies of the response with the Board at its above address and two copies with the person to whose submission response is made at the address set out in his submission, on or before March 14, 1974, and responses to submissions so filed will be available for public inspection after March 18, 1974, at the offices of the Board.

DATED at the City of Calgary, in the Province of Alberta, the 28th day of December, 1973.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Macleod
Board Solicitor

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